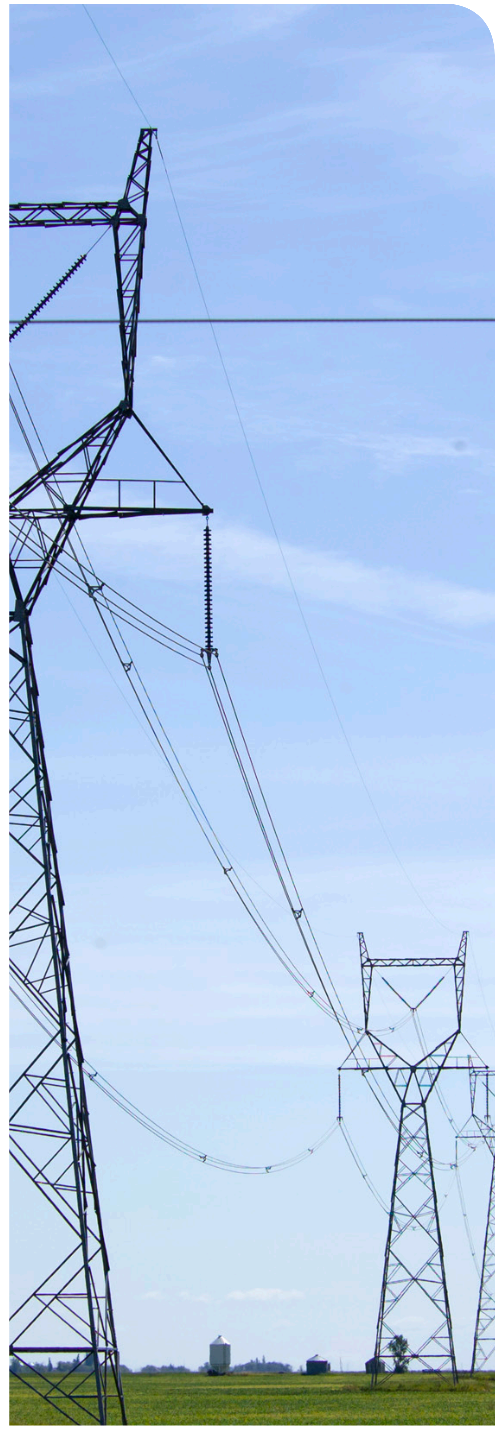
APPENDIX E



Needs For and Alternatives To

Manitoba Hydro

August 2013

Executive Summary

Introduction

Manitoba Hydro, a Crown Corporation, is committed to maintaining reliable, affordable and environmentally sustainable energy for its customers, while ensuring long-term financial sustainability. Manitoba Hydro meets its commitment through investments in Demand Side Management (DSM or Power Smart), new generation, and by exporting surplus electricity to utilities in United States (U.S.) and Canada. Exports have been a key factor in keeping Manitoba rates among the lowest in North America, contributing close to one-third of Manitoba Hydro's total revenues over the past decade.

Manitoba Hydro is seeking government approval for its Preferred Development Plan, which requires the following commitments in June 2014:

- start construction of the Keeyask generating station (G.S.) for a 2019 in-service date (ISD)
- proceed with a 250 MW export agreement with Minnesota Power (MP)
- proceed with a 100 MW export agreement with Wisconsin Public Service (WPS)
- proceed with a 750 MW U.S. transmission interconnection
- proceed with a 300 MW export agreement with WPS subject to satisfactory conclusion of negotiations currently still underway.

In addition, the plan would include Conawapa G.S., 1,485 MW, with an earliest ISD of 2026, although decisions on whether to construct Conawapa and its timing are not required now and would be made over the next few years.

Undertaking this plan would not preclude modifying it should future conditions suggest that it is prudent to do so. Activities would continue by Manitoba Hydro to protect an ISD for Conawapa as early as 2026, but conditions will be continually monitored to determine if such continued investments are worthwhile and, ultimately, to determine if Conawapa should be constructed and for what ISD. These decisions will be influenced by factors such as the 300 MW WPS export agreement, other export agreement possibilities, energy prices, capital cost and load growth. The early ISD of 2026 for Conawapa could be protected with a modest investment (approximately $50 million) up to the filing of the Environment Impact Statement in the summer 2015 after which the amount of investment would increase. A final decision on construction of Conawapa for an ISD of 2026 must be made by 2018.

In addition to the above major components, the Preferred Development Plan includes continued substantial investment in DSM/Power Smart and efficiency improvements to existing generation. Wind generation and natural gas generation will be incorporated into future development if and when required and other energy technologies may also be included in future development if and when they become economically viable.

Background

Purpose of the Needs For and Alternatives To Review

Manitoba Hydro has been created, and its activities governed, by *The Manitoba Hydro Act.* According to the Act, the purpose of Manitoba Hydro is 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."

In light of a demonstrated need for new Manitoba power supply by around 2023, Manitoba Hydro has formulated a Preferred Development Plan. This plan and alternatives to it are being assessed through Needs For and Alternatives To (NFAT) review under the auspices of the Manitoba Public Utilities Board (PUB). The PUB panel is to provide a report with recommendations to the Minister responsible for the administration of *The Public Utilities Board Act* by no later than June 20, 2014.

In addition to the NFAT review and government approval process, generation and transmission projects included in the development plan are subject to other regulatory processes at federal and provincial levels, including comprehensive environmental impact assessments. Matters included in those reviews are not addressed in this NFAT submission.

Manitoba Hydro Profile

With over $14 billion in assets and 5,700 megawatts (MW) of installed electricity capacity, Manitoba Hydro is one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro serves 548,000 electricity customers across Manitoba and 267,000 natural gas customers in the southern part of the province.

The vast majority of the electrical energy that Manitoba Hydro typically produces each year is from hydropower (approximately 98% on an energy basis). Manitoba Hydro also maintains two thermal generating stations to back up its hydro-electric system and purchases electricity from two independent wind farms. The provincial economy benefits from Manitoba Hydro's ongoing operations and future projects through employment, business transactions and the payment of taxes and levies.

Manitoba Hydro is highly rated (consistently higher than the national average for electric utilities) by its customers, according to the 2012 Canadian Electricity Association Public Attitudes Research Project, and continues to offer its customers the lowest average retail electricity price in North America.

Manitoba Hydro is committed to protecting the environment, contributing to the global reduction of greenhouse gas (GHG) emissions and maintains a diverse workforce including significant Aboriginal representation.

Manitoba Hydro recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation.

Manitoba Hydro's annual planning process includes the Corporate Strategic Plan, corporate-wide risk analysis, and an integrated planning cycle which includes development of an annual Economic Outlook, Load Forecast, Power Smart Plan, Power Resource Plan, Forecast of Interchange Revenues, Capital Expenditure Forecast and Integrated Financial Forecast.

Governance over Manitoba Hydro's plans is provided by the corporation's board, audit committee, Manitoba Crown Corporations Council, Crown Corporations Standing Committee of the Legislature and the Auditor General of Manitoba. Regulatory oversight is carried out by a number of provincial and federal authorities, including the Manitoba PUB.

Preferred Development Plan Facilities

The Preferred Development Plan consists of four main capital project components:

- the 695 MW Keeyask Project
- the 1,485 MW Conawapa Project
- the North-South Transmission Upgrade Project, with an ISD to coincide with the last units of Conawapa
- the 750 MW, 500 kilovolt (kV) Alternating Current (AC) Manitoba-Minnesota Transmission Project.

Keeyask

The Keeyask Project will take seven years to construct, with a total budgeted in-service cost estimate of $6.2 billion including interest and escalation based on a 2019/20 ISD. Manitoba Hydro will own and operate the Keeyask Transmission Project, whereas the Keeyask Generation Project will be owned by a partnership between Manitoba Hydro and four Keeyask Cree Nations (KCNs): Tataskweyak Cree Nation (TCN), War Lake First Nation (WLFN), York Factory

First Nation (YFFN) and Fox Lake Cree Nation (FLCN). The Joint Keeyask Development Agreement addresses the KCNs' income-sharing, training, employment, business opportunities, and involvement in environmental and regulatory affairs.

The Keeyask Infrastructure Project consists of the access road and the first stage of the construction camp. Work on this project is proceeding ahead of the decision to construct the generating station in order to provide employment, training and capacity building benefits to the four KCN partners, as well as to reduce lead times and risks for the project as a whole.

Efforts have been undertaken and continue with First Nation partners, to mitigate and reduce any adverse effects of the Keeyask Project and make environmental and socio-economic impacts as positive as possible.

Manitoba Hydro and its KCN partners are paying special attention to Lake Sturgeon. The Committee on the Status of Endangered Wildlife in Canada has designated the Nelson River sturgeon population as endangered, and the federal government is considering listing the species under the *Species at Risk Act*. Various measures will be implemented to address potential effects caused by the project: these include habitat replacement and a stocking program with the objective of an overall enhancement of sturgeon stocks in the Lower Nelson River.

Conawapa

The Conawapa Project will take 10 years to construct, with a budgeted in-service cost estimate of $10.2 billion, including interest and escalation based on a 2025/26 ISD.

Although the generation ownership structure has not been finalized, Manitoba Hydro is committed to providing the First Nations in the vicinity of the project with long-term sustainable benefits, early involvement and extensive consultations, and opportunities to participate in the environmental governance of the project. Manitoba Hydro has Conawapa process agreements in place with the Cree Nations while discussions and negotiations take place.

As with the Keeyask Project, plans for the Conawapa Project will include positive measures to address environmental and socio-economic effects. Studies in the past decade have involved five local Cree Nations in the vicinity of the project: FLCN, YFFN, TCN, WLFN and, to a somewhat lesser extent, Shamattawa First Nation.

North-South Transmission System Upgrade Project

The majority of the Conawapa G.S. power will be transmitted from northern Manitoba to southern customers on Manitoba Hydro's high-voltage direct-current (HVDC) transmission system. To transmit south the full amount of generated power once both Keeyask and Conawapa are in place, upgrades are required to the existing northern 230 kV AC system. This North-South Transmission System Upgrade Project will have an ISD coinciding with that of the last Conawapa units. The upgraded North-South Transmission System would be owned and operated by Manitoba Hydro and would cost an estimated $500 million including interest and escalation.

Manitoba-Minnesota Transmission Project

This proposed project consists of a 750 MW, 500 kV AC transmission line[1] in southeastern Manitoba, connecting at the border with MP's proposed Great Northern Transmission Line with an ISD of 2020. The project would enable power to be exported to the U.S. based on current sales agreements, improve reliability and import capacity in emergency and drought situations, and increase access to markets in the U.S.

This project is still in the study and negotiation phase. Manitoba Hydro will be responsible for the Manitoba portion of the interconnection, which is estimated to cost $350 million. Manitoba

[1] It should be noted that the transmission lines can be described by voltage size (kV) or by transfer capability (MW).

Hydro will also be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the facilities. For the Preferred Development Plan, it is assumed that Manitoba Hydro will be responsible for 40% of the capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities, with the remainder of the transmission costs to be borne by MP and WPS. The total cost of the U.S. portion of the 750 MW interconnection is in the order of $700 M (2020 base dollars, not including interest).

However, WPS recently advised that an investment in the 750 MW Interconnection Transmission does not match their current business objectives and that they will not invest in the line. They also advised that they will continue to negotiate the 300 MW Power Purchase Agreement; as of this writing that negotiation is proceeding under the auspices of the term sheet agreed to previously. In order to avoid becoming a majority owner in a U.S. transmission line, Manitoba Hydro will only enter into an arrangement where it will not own more than 49% of the interconnection facilities in the U.S. In return for investing in the U.S. portion of the transmission interconnection, Manitoba Hydro will benefit by having the right to use and/or sell its proportionate share of the U.S. transmission service associated with the new interconnection. Manitoba Hydro will also have the right to sell its share in the future. In the development plans without the WPS sale but with a 750 MW interconnection, a conservative assumption has been used whereby Manitoba Hydro will be responsible for approximately two-thirds of the capital.

While the Preferred Development Plan includes a 750 MW interconnection, some alternative development plans reduce the interconnection capacity to 250 MW. With a 250 MW, 230 kV AC line, Manitoba Hydro would be responsible for $95 million (including interest and escalation) in capital costs for the Manitoba portion but would not be responsible for capital or ongoing operating costs associated with the U.S. portion of the interconnection facilities.

Trends and Factors Influencing North American Electricity Supply

Several notable trends and factors are currently influencing electricity markets and resource decisions. These trends affect existing resources, the need for new generation, the costs of competing resources, and the market price for electricity. The need for new generation in the U.S. and Canada is being driven by:

- modest load growth
- an aging generation fleet
- uncertainty as to the life expectancy of nuclear plants
- various environmental and energy policies that could hasten the retirement of coal plants.

North American Demand for Electricity

Electricity demand in both Canada and the U.S. is expected to continue to increase over the 35-year planning horizon, although at a slower rate than has been historically observed. Recent years have seen lower rates of demand growth for electricity throughout North America due largely to increasing energy efficiency and the migration of industrial processes to other countries. Despite this trend the U.S. Energy Information Administration's Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).

Environmental and Energy Policies

Environmental considerations and policies are and will continue to be major factors influencing electric power resource choices and the market price for electricity. Policies such as renewable portfolio standards that encourage an increasing percentage of renewable energy within specific jurisdictions are widespread. The eligible renewable technologies within each specific program vary by state but in general are trending towards more inclusive treatment of hydropower. Minnesota's program includes hydropower from stations that are less than 100 MW while Wisconsin's program will include all new hydro regardless of its size.

Global interest and attention to the effects of climate change are having an impact on the energy industry. Manitoba Hydro expects that some form of significant climate change regulation or legislative action in the U.S. is likely within the next 10 years. This would be a significant driver for increasing electricity market prices and would favour hydropower as a virtually GHG-free form of generation.

Energy Price Considerations

Fuel pricing is one of the most important considerations driving electrical resource decisions and regional market prices for electricity. Recent reductions in cost due to developments in shale gas extraction have increased the attractiveness of natural gas as a supply source, particularly in relation to coal.

Natural gas prices have exhibited considerable historic volatility. However, industry analysts generally foresee a range of potential prices, with reference cases—i.e. most likely outcomes—that project moderate price growth over the next decade as marginal production costs rise and demand grows.

Market prices for electricity have dropped markedly since 2006-2008 in the Midcontinent Independent System Operator, Inc. (MISO) region. However, moderate real price growth is expected in the future, based on a corresponding escalation in natural gas and coal prices, increased environmental regulations, expected coal generation retirements and future regulations to reduce GHG emissions. The general outlook for moderate real growth in electricity prices is confirmed by independent North American price forecast consultants.

Implications For Preferred Development Plan

These industry trends support Manitoba Hydro's Preferred Development Plan in confirming that there is a need for new sources of supply, a growing preference for clean, renewable, non-emitting power and an expectation that wholesale electricity prices will increase in real terms.

While resulting in low emissions relative to coal, natural gas generation still carries a considerable GHG emission liability and as well is exposed to expected price increases and likely price volatility.

Manitoba Hydro's Need for New Power Resources

To determine Manitoba's electricity supply need, Manitoba Hydro regularly assesses domestic demand (load growth net of reductions resulting from DSM) and firm export commitments to arrive at total demand. Total demand is then compared to current supply. Total demand is currently projected to exceed existing supply beginning around 2023 even with no new export commitments. The need for new supply to meet Manitoba domestic load is the principal driver of the Preferred Development Plan.

Domestic Load Growth

Manitoba's electrical energy consumption has grown, on average, at an annual rate of 1.7% over the past 10 years. Over the next 20 years, growth in energy consumption is forecast to continue at an average annual rate of 1.6%. This trend takes into account the effects of future savings due to energy efficiency codes and standards but not DSM programs. When projected DSM (Power Smart) programs are taken into account, forecasted energy use growth rate is reduced by about 0.1% to 1.5%.

The Manitoba load is expected to grow in all sectors, the result of population growth, increased average energy use per residential customer and anticipated industrial and commercial expansion by a number of businesses.

Reducing Demand Through Demand Side Management

Manitoba Hydro's DSM programs consist of energy conservation and load management activities designed to reduce customer demand for power. Savings to date have deferred the need for new generation by 4 years. The 2013-2016 Power Smart Plan targets additional energy savings of 1,552 gigawatt (GWh) and 490 MW by 2027/28.

Manitoba Hydro's DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba. An updated DSM Market Potential Study has recently been completed and is included in the NFAT submission. Manitoba Hydro will update its Power Smart Plan, in consultation with government by March, 2014 and will incorporate the information contained in the DSM Market Potential Study. The updated Power Smart plan will be included in future Power Resource Plans as part of any development plan that is pursued by Manitoba Hydro at the conclusion of the NFAT process.

Firm Export Sale Commitments

The wholesale electricity export market is integral to Manitoba Hydro fulfilling its mandate to provide economical and reliable power to Manitobans.

Export sales, both firm and surplus, provide an outlet for excess electricity in the early years of new hydropower generating stations and for the many years when water flows exceed minimum (dependable) levels. In times of drought or extremely cold weather or system emergencies, firm arrangements with export customers allow for imports to ensure reliability of supply.

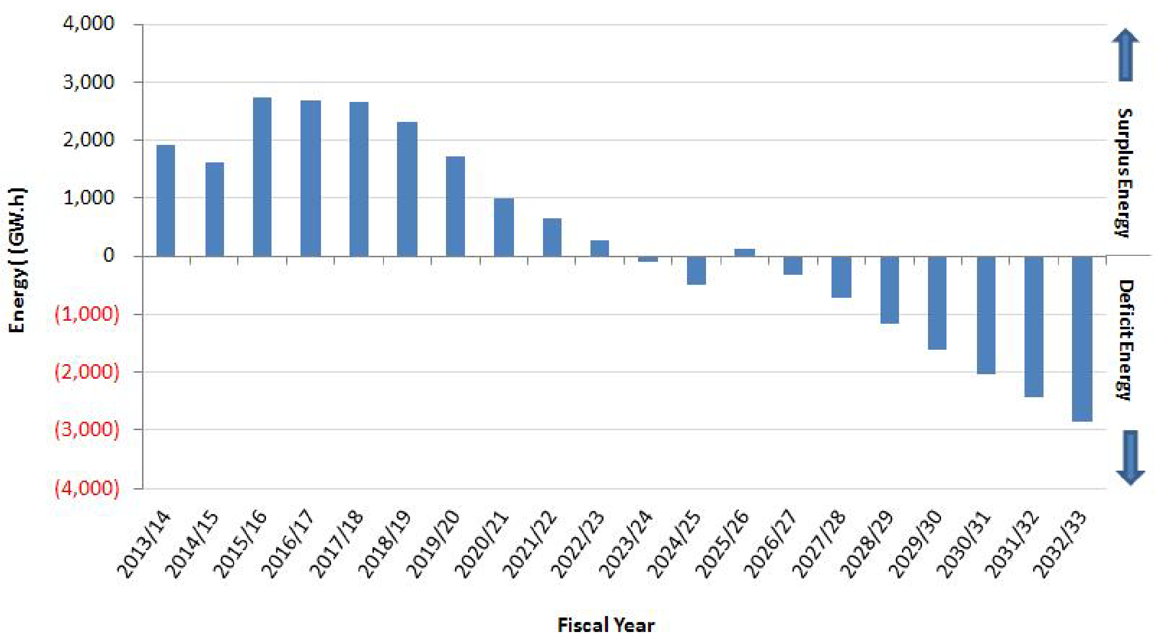
Long-term firm export sales contracts entail an obligation to supply except in agreed-upon situations where security and reliability of supply to Manitoba customers would be compromised, for example during periods of system emergencies and under certain drought conditions.

Supply and Demand

Manitoba Hydro plans its system so as to have sufficient dependable energy resources to supply firm energy demand in the event of a repeat of the lowest water supply conditions on record. System capacity must also be sufficient to meet the Manitoba winter peak demand. To determine if new supply is needed, Manitoba Hydro annually compares supply and demand values for each year.

Manitoba Hydro's analysis of current supply shows that supply will be exceeded by demand in or around 2023.

Figure 1 ENERGY BALANCE – DEPENDABLE ENERGY SHOWING DEFICIT BY **2023**



The exact year that new supply is required will depend on load growth rates and supply factors such as earlier retirement of the natural gas generation at Selkirk and availability of dependable energy imports. It is prudent and necessary, therefore, to plan for providing new Manitoba supply starting in or around 2023.

The Manitoba Hydro System, Interconnections and Export Markets

Generation

Manitoba Hydro's existing supply resources can be divided into four resource types: hydro-electric generation, thermal generation, wind generation and imports. Hydro-electric power is by far the most significant resource in the Manitoba Hydro generating system, providing almost

90% of the generating capacity that Manitoba Hydro owns and typically about 98% of electrical energy.

Manitoba Hydro's generation is affected by variability in water supply. There is a 350% difference between the lowest and highest recorded water supply conditions on record. Generating stations are planned to meet the energy demand under the lowest flow on record (as well as the highest winter peak demand). As a result, in all but drought years there will be surplus energy which can be sold on the export market if transmission interconnections are available. Surplus energy is also available as a result of the large-scale increments of generation typical of hydro development. Until domestic load has caught up with the total supply from new hydro generation, this surplus energy is either exported or the production is foregone and the water is spilled.

Transmission

Electricity is delivered from Manitoba Hydro's generating stations to Manitoba customers over a network of transmission lines with two major components – the AC transmission system and the HVDC system, which transmits electricity south from the generating stations in the north.

Cross-Border Interconnections and Their Benefits

Manitoba Hydro's transmission interconnections with adjacent provinces and states are a very important part of Manitoba Hydro's transmission system, providing benefits as follows:

- improving reliability by enabling imports during drought conditions and under supply contingencies (e.g. temporary loss of supply due to equipment outages)
- increasing revenues by enabling the export of surplus hydro power and import of market energy at costs lower than the cost of thermal resources available within Manitoba
- providing the predominantly hydro system with needed resource diversity as a supplement to thermal generation in Manitoba

- displacing fossil fuel generation in export markets. Manitoba Hydro currently estimates that, globally, its exports displace 0.75 tonnes of CO_2 per megawatt-hour (MWh).

Manitoba Hydro currently has five cross-border interconnections with Saskatchewan, three interconnections with Ontario and four interconnections with the U.S. Current technical limits are indicated in Table 1:

Table 1 EXPORT TRANSFER LIMITS AND IMPORT TRANSFER LIMITS

Interconnection	Firm Export Schedule Limit	Firm Imports Transfer Capability for the Planning Horizon
U.S.	1,950 MW	700 MW
Ontario	200 MW	0 MW
Saskatchewan	150 MW	0 MW

The 1,950 MW export limit to U.S. markets is equivalent to 2% of the peak demand in the MISO region; the large size of the MISO system gives assurance that energy imports and emergency capacity support will be available for Manitoba when it is needed—both for the current interconnection size and if the import capability is expanded by the new interconnection from 700 MW to 1,450 MW. Similarly, the MISO market is large compared to Manitoba export levels, increasing confidence in the ability for Manitoba to obtain either short-term or long-term export sales.

In terms of opportunities in Canadian markets:

- The Ontario energy market is approximately one-quarter the size of the MISO market. There are two major barriers to a major long-term Manitoba Hydro power sale to Ontario: distance and Ontario government policy which strongly favours in-province generation. The Manitoba-Ontario interconnection is with Northwestern Ontario, a large, sparsely populated area with a proportionally small peak load of 750 MW.
- With respect to Saskatchewan, Manitoba Hydro and SaskPower have recently signed Memoranda of Understanding whereby the utilities are to engage in sale discussions for

existing and new hydro exports to both northern and southern Saskatchewan—across all time frames—for volumes ranging from 25 MW to 500 MW; discussions are also to include the possibility of new transmission interconnections.

The Window of Opportunity for a New U.S. Interconnection

When new transmission is added to the system, Manitoba Hydro's access to markets is enhanced for the entire life of the transmission facilities, not only for the term of committed contracts. Additional interconnection capacity is important to increase short-term export sales by helping to minimize spill at the hydro plants in periods of ample streamflow conditions and to maximize export of energy during the higher valued on-peak periods rather than off-peak periods.

Manitoba Hydro, working with its export customers, currently has the opportunity to influence what new transmission is built in the U.S. MISO region and to ensure that it is compatible with Manitoba Hydro's Preferred Development Plan. A new 750 MW interconnection is required to enable the additional long-term export sales to MP and WPS. These two sales, plus a sale to Northern States Power (NSP) which has already been approved, would provide financially attractive fixed prices. Manitoba Hydro would therefore receive predictable and stable revenue to reduce the costs borne by domestic customers. Specifically, these sales are:

- MP — 250 MW (2020-2035)
- WPS — 300 MW (2020-2040), subject to satisfactory conclusion of negotiations
- NSP — 125 MW expansion of existing approved sale (2021-2025).

There is risk inherent in deciding not to proceed with a new interconnection as part of the development plan. MP has committed to champion a new transmission interconnection with Manitoba through its service territory, in which it has a strong relationship with the local land owners—a critical component of building a new transmission line. However, the current favourable political, regulatory and business conditions in the U.S. for constructing a new transmission interconnection will not continue indefinitely. Our U.S. utility customers are currently making decisions on their future energy supply mix, as they move away from nuclear and coal-generated energy and consider the price volatility of the natural gas market. Should Manitoba Hydro be unable to supply adequate amounts of hydropower, these utilities will pursue other supply sources. As well, federal and state administrations continuously modify their policies and it cannot be assumed that a new U.S. transmission interconnection can be approved and constructed at a given future date. This represents a window of opportunity for Manitoba Hydro given that it would be extremely difficult, probably impossible, for Manitoba Hydro to develop a line in the U.S. without the committed participation of a U.S. partner like MP.

Foregoing this opportunity would likely preclude the building of significant new interconnection capability until well beyond the required 2023 time horizon for new Manitoba energy supply.

Screening of Manitoba Resource Options

A multi-stage screening process was utilized to narrow the field of appropriate resource supply options. The candidates consisted of 17 resource option technologies potentially suitable for utility-scale generation, including DSM (Power Smart), imports, wind, solar, biomass, natural gas as well as hydro.

The screening process included evaluations of technical, environmental, socio-economic and economic characteristics of each of the options.

Based on these evaluations, resources such as solar, nuclear, coal and biomass were screened out as not sufficiently attractive to consider as primary supply contenders in the development plans.

Specific resource options were selected at the conclusion of the screening as suitable candidates to be included within individual development plans mainly because of their cost competitiveness and environmental attractiveness:

- additional DSM
- Keeyask G.S.
- Conawapa G.S
- GE 7FA Heavy Duty Combined-Cycle Gas Turbine
- GE 7FA Heavy Duty Simple-Cycle Gas Turbine
- GE LM6000 PH Aeroderivative Simple-Cycle Gas Turbine
- generic 65 MW Wind Farm
- contractual import agreements.

Determination of Potential Development Plans

The next step was to develop and evaluate potential alternative development plans using the short-listed resource options. The number and size of resource options were selected to cover Manitoba's energy and capacity needs for the next 35 years.

Different combinations of supply resources enable comparison of the trade-offs between their characteristics. For example, the low capital cost and high operating cost of gas turbines can be compared to the export revenue potential and low operating costs of hydro-electric generation. This analysis led to the identification of 15 alternative development plans that were evaluated based on three groupings:

- Keeyask 2019 with a 750 MW U.S. Interconnection
  - Both MP and WPS Sales - two plans (one with Conawapa (preferred) & one with gas generation to follow Keeyask)
  - MP Sale but not the WPS Sale – three plans
- Keeyask 2019 with a 250 MW U.S. Interconnection – three plans
- Plans that meet Manitoba Hydro's domestic load and firm export commitments starting in 2022/23 with no new export sales or U.S. interconnection – seven plans

(The 750 MW interconnection would have 750 MW of export and import capability whereas the 250 MW interconnection is assumed to have 250 MW of export capability but only 50 MW of import capability.)

Included in the 15 plans above, are two plans with wind generation which were also evaluated, but were found to be clearly uneconomic and thus were not carried through the full set of evaluations.

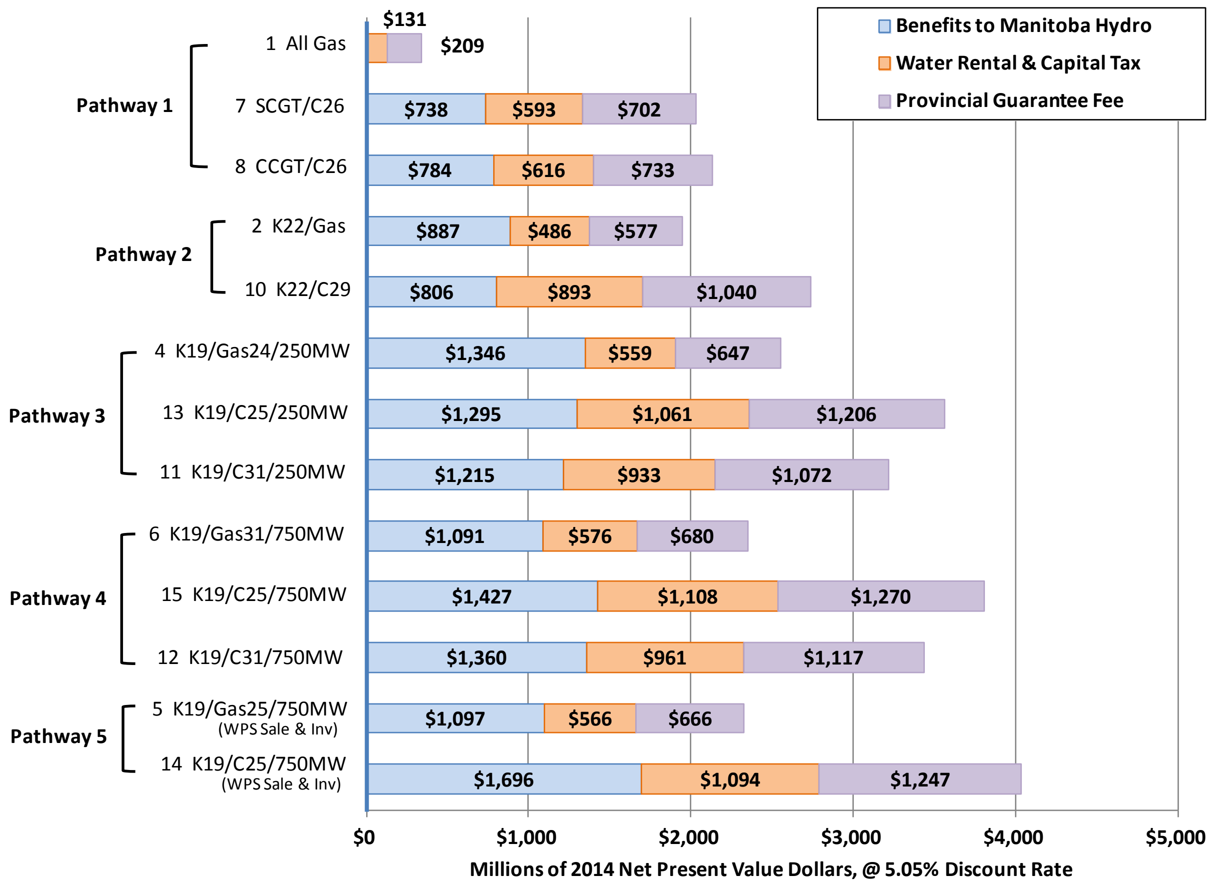
Economic Evaluation of the Potential Development Plans

The third step was to comparatively evaluate the preferred and alternative development plans using economic evaluation principles in order to allow the comparison of alternative options on the basis of their relative costs and benefits. The economic evaluation of development plans was conducted over four phases of analysis:

- analysis using “reference” (most likely) assumptions
- probabilistic analysis to test potential variations to reference assumptions
- sensitivity and “stress testing” of the proposed plan and the best alternative plans
- “Pathways” analysis to assess the flexibility of options to change course based on future conditions. The use of pathways recognizes the reality of allowing decisions to be made incrementally as uncertainties resolve.

The following figure sets out the Net Present Value (NPV) comparison for 13 of the development plans, including benefits to Manitoba Hydro and potential cash transfers to the Province through the provincial guarantee fee, water rental and capital tax. The calculations were done using reference assumptions and show the incremental net benefits accumulated during the life of each plan discounted to today’s dollars.

Figure 2 COMPARISON OF DEVELOPMENT PLAN NET PRESENT VALUES INCLUDING POTENTIAL CASH TRANSFERS TO THE PROVINCE



Note: NPVs calculated with a real discount rate of 5.05%

This evaluation, based on 2012 reference scenario assumptions, indicates that:

- The plan with the 750 MW Interconnection and WPS sale ("the Preferred Development Plan") provides higher economic benefits than any of the other plans.
- The plans with the most benefit are those that include Keeyask G.S., Conawapa G.S. and a new interconnection.
- Compared to the All Gas Plan, the NPV benefit of the Preferred Development Plan is higher by $1,696 million considering only Manitoba Hydro economics and $3,697 million when also considering Manitoba Hydro transfers to the Province from provincial debt guarantee fees, water rentals and capital taxes. The total corporate and provincial economic NPV of $3,697 million is equivalent to almost $300 million (2020 $) per year

for 60 years starting in 2020 or about $600 per year for each of Manitoba's approximately 500,000 residential households.

Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities

Manitoba Hydro then tested the sensitivity of the most attractive development plans to changes in assumptions.

The uncertainty analysis was performed through a combination of (i) sensitivities, in which a single variable was tested, and (ii) scenarios, in which multiple variables were tested in combination. In order to fully understand the uncertainty of the evaluations, a comprehensive review was conducted of all the variables that contributed to the economic evaluations.

Analysis demonstrated that three of these variables had the most significant impact on the economic evaluations:

- energy market prices (natural gas and electricity)
- capital cost of new supply
- Manitoba Hydro discount rate (cost of capital).

The reference assumptions (i.e. most likely conditions) were combined with low and high assumptions for each of these three variables to create 27 (3 X 3 X 3) scenarios applied to each of the 15 plans, resulting in 405 (27 X 15) distinct cases. (The two wind generation plans are not included in the tables and figures). Probabilities were then assigned to the scenarios to determine the expected value for each development plan. Tables 2 and 3 summarize the resulting analysis and cases.

These 27 cases for each plan are combined using their respective probabilities to create cumulative probability curves for each plan which are a standard representation of this analysis. These curves were used to assess the relative attractiveness and risk profile of each plan under a broad range of potential future outcomes. The curves for selection of main plans are depicted in Figures 3 and 4. An explanation of cumulative probability curves can be found in ***Chapter 10 - Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities***, Section 10.1.4.1 of the submission.

Table 2 depicts the economic evaluation comparisons to account for uncertainties in the export/gas prices, capital cost and discount rate. There are 27 scenarios comprising all the combinations of high, reference and low for each of the three parameters export/natural gas prices, capital cost and discount rate. Green and red shadings are used to indicate the relative favourability or un-favourability of results.

At the top of the table there is reference to five “pathways”. Such groupings recognize the need for flexibility as to how any development plan will unfold over the long-term after the initial decisions are made at the completion of the NFAT process in mid-2014. The pathways are thus representative of the outcomes flowing from the choices that will be decided upon as the next step in Manitoba’s electricity future. Some of the questions addressed in the pathway analysis include:

- Should the next major electrical resource in Manitoba be gas or hydro? (i.e., a choice between Pathway 1 and one of the other pathways)
- Should a 250 MW interconnection proceed along with the 250 MW MP sale? (i.e., should Pathway 3 proceed?)
- Should a 750 MW interconnection proceed along with the 250 MW MP sale? (i.e., should Pathway 4 proceed?)
- Should a 750 MW interconnection proceed along with the 250 MW MP sale, 300 MW WPS sale and transmission development agreements with both MP and WPS? (i.e., should Pathway 5 proceed?)

Pathways 4 and 5 are both associated with the Preferred Development Plan because, compared to the other pathways, the single most defining feature of the Preferred Development Plan relative to the other plans is the 750 MW interconnection. The main difference between

Pathway 4 and 5 is that in Pathway 5 it is assumed there is a concluded sale and related transmission development agreement with WPS, while in Pathway 4 this is not the case.

Table 2 **NET PRESENT VALUE BENEFITS OF ALTERNATIVE DEVELOPMENT PLANS UNDER 2012 HIGH, REFERENCE AND LOW ASSUMPTIONS FOR ENERGY PRICES, CAPITAL COSTS AND DISCOUNT RATES**

		Pathway	Pathway 1			Pathway 2		Pathway 3			Pathway 4			Pathway 5	
		Development Plan	1	7	8	2	10	4	13	11	6	15	12	5	14
			All Gas	SCGT/C26	CCGT/C26	K22/Gas	K22/C29	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
														WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												
Low	Low	H	0	734	514	251	-22	853	584	537	625	401	489	1188	1202
		Ref	0	648	567	517	263	1172	925	883	919	872	911	1433	1639
		L	0	592	620	657	474	1357	1178	1148	1072	1217	1224	1544	1955
	Ref	H	0	-834	-1068	-749	-2076	-448	-2047	-1698	-729	-2353	-1861	-267	-1692
		Ref	0	-790	-913	-487	-1704	-114	-1576	-1258	-393	-1768	-1362	49	-1137
		L	0	-744	-779	-342	-1428	87	-1223	-926	-202	-1335	-993	224	-730
	High	H	0	-1488	-1721	-1179	-2863	-1087	-3233	-2617	-1386	-3587	-2826	-1001	-3014
		Ref	0	-1385	-1521	-923	-2462	-744	-2701	-2141	-1029	-2950	-2299	-648	-2406
		L	0	-1292	-1352	-778	-2165	-534	-2303	-1787	-817	-2478	-1914	-440	-1958
Ref	Low	H	0	3253	3310	2502	4174	3218	5220	4680	2973	5511	5013	2910	5866
		Ref	0	3167	3364	2768	4458	3537	5561	5026	3267	5983	5435	3155	6304
		L	0	3111	3417	2908	4669	3721	5814	5291	3420	6327	5749	3266	6620
	Ref	H	0	694	628	625	434	1012	823	775	756	841	861	780	1141
		Ref	0	738	784	887	806	1346	1295	1215	1091	1427	1360	1097	1696
		L	0	784	917	1031	1083	1547	1648	1547	1282	1860	1729	1272	2103
	High	H	0	-429	-544	-218	-1140	-50	-1199	-917	-310	-1306	-942	-268	-1040
		Ref	0	-325	-344	39	-739	292	-668	-441	47	-669	-416	86	-432
		L	0	-233	-175	184	-441	503	-269	-87	259	-196	-30	294	16
High	Low	H	0	6079	6411	4936	8790	5742	10254	9230	5428	10890	9844	4740	10807
		Ref	0	5993	6465	5202	9074	6062	10595	9576	5722	11361	10266	4985	11244
		L	0	5937	6518	5342	9285	6246	10849	9841	5875	11706	10580	5096	11560
	Ref	H	0	2398	2494	2099	3172	2556	3903	3466	2285	4151	3729	1871	4098
		Ref	0	2442	2649	2361	3543	2890	4375	3906	2620	4736	4228	2187	4653
		L	0	2489	2783	2505	3820	3091	4728	4238	2812	5170	4597	2362	5060
	High	H	0	747	742	807	725	1036	961	917	783	1027	1019	482	994
		Ref	0	850	942	1064	1126	1379	1492	1392	1141	1664	1546	835	1602
		L	0	943	1111	1208	1424	1589	1891	1747	1353	2136	1931	1043	2050

Colour Legend < -3000 0 > 3000

Table 3 further analyses these results by providing the probabilistic average of the differences for each plan relative to the All Gas Plan and provides an indication of the upper and lower range of benefits each plan would be able to achieve.

Table 3 DEVELOPMENT PLAN ECONOMIC EVALUATION SUMMARY

Pathway	Pathway 1			Pathway 2		Pathway 3			Pathway 4			Pathway 5	
	All Gas with no new interconnection			Keeyask with no new interconnection		Keeyask with 250 MW new interconnection (MP Sale)			Keeyask with 750 MW new interconnection (MP Sale)			Keeyask with 750 MW new interconnection (WPS & MP Sales)	
Development Plan	1	7	8	2	10	4	13	11	6	15	12	5	14
	All Gas	SCGT/C26	CCGT/C26	K22/Gas	K22/C29	K19/Gas24 /250MW	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
												WPS Sale & Investment	
	Millions of 2014 NPV dollars												
Ref-Ref-Ref NPV	0	738	784	887	806	1346	1295	1215	1091	1427	1360	1097	1696
Expected Value Difference From All Gas	0	525	529	634	418	1041	782	806	776	830	891	842	1155
90th Percentile - "Reward"	1905	1956	2070	2007	2601	2479	3180	2953	2215	3360	3220	2256	3377
10th Percentile -"Risk"	-3502	-1217	-1424	-1249	-1692	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429

"Ref-Ref-Ref NPV" = results for reference scenario assumptions for energy prices, capital costs and discount rate (relative to All-Gas reference case result)

"Expected Value" = probabilistic weighted average of results for each of the 27 scenarios (relative to All-Gas Expected Value)

"90th Percentile-Reward"= 90^{th} percentile probability upside benefit potential of that plan (relative to All-Gas reference scenario result)

"10th Percentile-Risk"= 10^{th} percentile probability downside risk of that plan (relative to All-Gas reference scenario result)

Figure 3 PROBABILITY CURVES FOR 3 PLANS: ALL GAS, 250 MW INTERCONNECTION 750 MW INTERCONNECTION & WPS

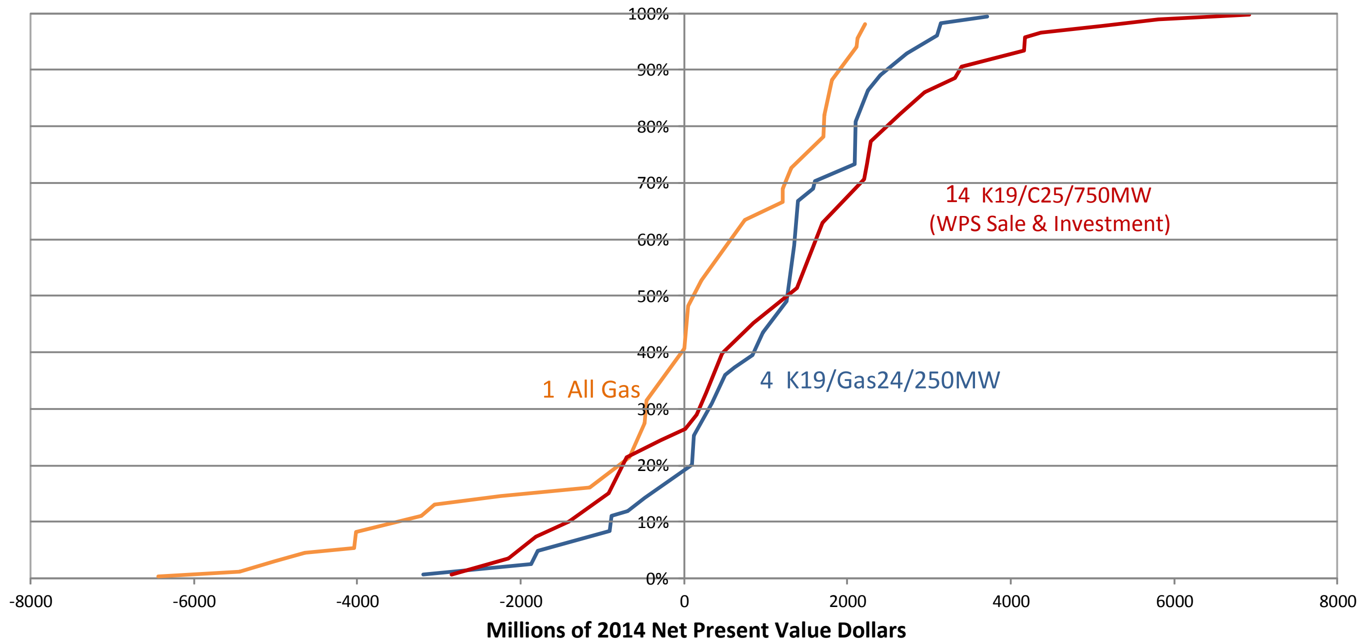
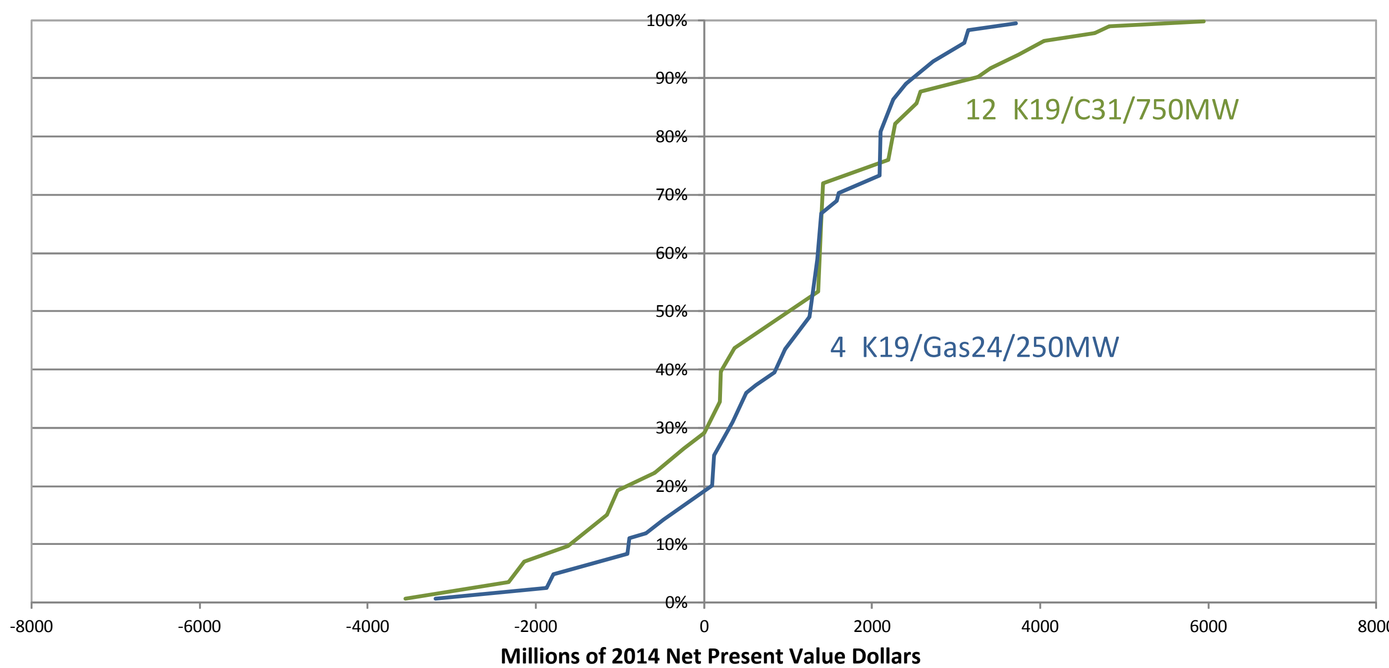


Figure 4 PROBABILITY CURVES FOR 2 PLANS: 750 MW INTERCONNECTION WITH & WITHOUT WPS



The brief conclusions from the economic evaluations summarized above and contained in ***Chapters 9 - Economic Evaluations - Reference Scenario*** and ***Chapter 10 - Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities*** are:

- For plans with no new interconnection:
  - Plans with hydro next and no interconnection are clearly more economic than the All Gas Plan.
  - Plans with Keeyask G.S followed by Gas and no interconnection are more economic than plans with Conawapa G.S next.
- Plans with either 250 MW or 750 MW new interconnections are clearly more economic than plans with no new interconnections.
- Comparing plans with a 250 MW new interconnection (Pathway 3) and a 750 MW new interconnection but without the proposed 300 MW WPS sale (Pathway 4), the economic evaluations indicate no clear overall preference between Pathways 3 and 4 and suggest that:
  - If there is an expectation Conawapa will be built within the next two decades, the 750 MW interconnection (Pathway 4) is more economic.
  - If there is an expectation Conawapa will not be built for several decades, the 250 MW interconnection (Pathway 3) is more economic.
- The most economic plan with the 250 MW interconnection (Pathway 3) is more economic than the most economic plan with the 750 MW interconnection (Pathway 4).
- The Pathway 5 plan with the proposed 300 MW WPS Sale and WPS Transmission Agreement and Keeyask G.S. followed by Conawapa G.S. is generally more economic than the other plans. However, under certain scenarios it is less economic. One driver of such cases is when energy prices are low; this can be mitigated by displacing Conawapa G.S. with gas generation.
- The economic evaluations undertaken conclusively demonstrate that Pathway 3, 4 and 5 plans are clearly preferred to Pathway 1 and 2 plans. However, a clear and decisive preference between the 250 MW and 750 MW interconnection plans (Pathways 3, 4

and 5) cannot be established on the basis of only these evaluations but must consider additional information such as:

- qualitative consideration of factors not currently included in economic (and financial) evaluations such as the outcome of WPS negotiations, possible alternate or additional export agreements and updates to interconnection capital costs
- financial and multiple accounts evaluations
- flexibility and risks
- reliability and energy security
- environmental and socio-economic impacts and benefits.

Financial Evaluation of Development Plans

The financial evaluation was performed on 8 development plans that provide a representative sample of the range of potential plans with respect to the economics as well as mix of generation resources. The financial evaluation was prepared using information from pro forma financial statements that utilize the same framework for scenario uncertainty analysis that is used in the economic uncertainty. This resulted in 27 (3 x 3 x 3) scenarios for each of the 8 plans, for a total of 216 pro forma financial statements. The financial evaluation focused on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk of the various development plans.

Recognizing that during the capital investment period associated with new generation there will be downward pressure on Manitoba Hydro's financial ratios, the financial evaluation assumes even-annual rate increases in order to achieve the targeted debt:equity ratio of 75:25 by the end of 2031/32. Once the debt:equity target is reached, the projected annual rates for the remainder of the 50-year financial forecast period are calculated to maintain the corporation's interest coverage ratio target of 1.20. The financial evaluation has not been designed to establish specific rate strategies but to compare impacts on rates and on Manitoba Hydro's financial strength among alternative plans.

The following table sets out the projected key financial metrics for the 8 development plans evaluated, including cumulative nominal rate Increases by 2061/62 - compared to All Gas, projected even-annual rate increases (2014/15 to 2031/32), equivalent even-annual rate increases over the forecast period (50-years), the nominal balances of net fixed assets, net debt and retained earnings as at 2031/32 and 2061/62. The projected financial metrics are summarized from the pro forma financial statements using reference assumptions.

Table 4 FINANCIAL EVALUATION SUMMARY

Pathway	Interconnection	Development Plan	(A) Cumulative Nominal Rate Increases by 2061/62 - Compared to All Gas	(B) Projected Even-Annual Rate Increases (2014/15 to 2031/32)	(C) Equivalent Even-Annual Rate Increases over the Forecast period (50 Years)	(D) Net Fixed Assets	(E) Net Debt	(F) Retained Earnings	(G) Net Fixed Assets	(H) Net Debt	(I) Retained Earnings
						As at 2031/32 in Billions of Nominal Dollars			As at 2061/62 in Billions of Nominal Dollars		
1	No New Interconnection	1 All Gas	-	3.43%	2.07%	$20.2	$14.7	$4.8	$31.8	$15.5	$10.7
		7 Gas C26	-42%	3.86%	1.72%	$28.1	$20.4	$6.7	$34.4	$14.6	$13.7
2		2 K22 Gas	-36%	3.49%	1.77%	$25.3	$18.4	$6.0	$33.9	$15.3	$12.8
3	250 MW Interconnection	4 K19 Gas 250 MW	-33%	3.42%	1.80%	$24.8	$18.1	$5.9	$34.0	$15.6	$12.6
		13 K19 C25 250 MW	-65%	3.98%	1.50%	$32.7	$23.8	$7.9	$36.7	$15.0	$15.6
4	750 MW Interconnection	12 K19 Imp C31 750 MW	-65%	3.80%	1.50%	$35.2	$25.7	$8.5	$38.6	$15.6	$16.8
		6 K19 Imp Gas 750 MW	-33%	3.50%	1.79%	$25.0	$18.2	$6.0	$33.6	$15.2	$12.6
5		14 K19 Sales C25 750 MW	-70%	3.95%	1.44%	$32.9	$24.0	$7.9	$36.8	$15.1	$15.7

The following summarizes the financial evaluations, with a focus on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk:

Future Customer Rates

- Rate increases are required for all evaluated alternatives. The financial evaluation shows that higher rates are required in the medium term under all of the development plans, regardless of whether the plan is gas-based or hydro-based. New energy supply cannot be provided at the same current low rates that Manitoba Hydro customers have enjoyed over the last two decades.
- In the long-term, development plans with both Keeyask and Conawapa G.S. are projected to have the lowest cumulative rate increases which range between 65% to 70% lower than the All Gas plan under the reference scenario. Development plans with both Keeyask and Conawapa G.S. provide incremental dependable and surplus energy which translate to savings for Manitoba customers in the long run.
- In the medium term, the capital intensive plans that include both Keeyask and Conawapa G.S. are projected to have cumulative rate increases that are generally higher than other alternatives. Cumulative rates under the Preferred Development Plan "cross-over" compared to all other plans and begin to provide benefit to customers in a relatively short timeframe (10-15 years) following the ISD of the Conawapa G.S.
- The Preferred Development Plan is projected to have the lowest overall rates to Manitoba customers in the long-term.

Financial Risk

- In the long-term, development plans that include Keeyask and Conawapa G.S. have the strongest projected balance sheet with high levels of fixed assets and retained earnings. By the end of the study period retained earnings are projected to be between $4.9 billion to $6.1 billion higher than the All Gas plan.
- Net debt levels converge towards the end of the study period for all development plans.

- In the medium term, while net debt levels are the highest with the development plans that include both Keeyask and Conawapa G.S., as these plans have the overall highest capital investment, they also have the highest fixed assets and retained earnings.
- Development plans with both Keeyask and Conawapa G.S. are more robust in their ability to absorb adverse financial impacts, in the medium term and extending through to the end of the study period, given their comparatively higher level of retained earnings.

2013 Update to Forecasts and DSM Sensitivities

The economic and financial evaluations discussed above were based on the 2012 load forecast and other related planning assumptions, with the export price forecast adjusted, primarily downward in anticipation of 2013 updates. The following factors have changed for the 2013 analysis compared to the NFAT analysis:

- domestic load forecast is slightly lower
- export price forecasts are approximately 7% higher
- real discount rate has increased from 5.05% to 5.4%
- an export arrangement (the Great River Diversity Exchange) is extended to end in 2030 instead of 2025.

As a consequence of these changes, ISDs for new generation have been deferred by approximately 1-year, and NPVs have changed, though not to a degree that alters the conclusions as the relative ranking between the respective plans and pathways remains the same.

A sensitivity was undertaken using an increased level of DSM equal to 1.5 times the 2013 DSM forecast and a stress test was also undertaken using an increased level of DSM equal to 4.0 times the 2013 DSM forecast. The sensitivity and stress test demonstrated that increasing the DSM within a reasonable range (1.5 times) and for an ideal range (4.0 times): 1) did not change the conclusion that the plans with 750 MW or 250 MW interconnections are clearly more economic compared to plans without new exports or new interconnection and 2) did not change the relative rankings of the 750 MW and 250 MW plans with respect to each other. Based on these results, it was not necessary to further include different levels of DSM in the detailed evaluations of the development plans to be able to assess the attractiveness of the plans with the new interconnections and exports.

In addition, some recent developments of strategic significance are:

WPS Export Sale and Transmission Investment Agreement Status

The proposed 300 MW WPS Export Sale and the transmission investment arrangements with WPS and MP are still in negotiation as of early August 2013 while this NFAT submission is being finalized. As noted earlier, WPS recently advised that they will not invest in the 750 MW interconnection transmission line but will still negotiate the 300 MW Power Purchase Agreement.

Concurrently, negotiations are proceeding between MP and Manitoba Hydro to revise the arrangement with MP to increase their investment in and ownership of the 750 MW Interconnection. Manitoba Hydro would increase its investment and ownership but would not become a majority owner.

It should be noted that, unlike the 300 MW WPS Sale, the 250 MW MP Sale Power Purchase Agreement is final, has been signed and has been approved by MP's state regulator but is still subject to other regulatory approvals in the U.S. and Canada.

Manitoba Hydro Investment in a 750 MW Interconnection

The evaluations of Pathways 4 and 5 assume that Manitoba Hydro will be investing in and owning a portion of the U.S. segment of the 750 MW, 500 kV interconnection and that the percentage amount owned stays constant for the life of the interconnection asset. It will be Manitoba Hydro's intent to arrange for some or all of the Manitoba Hydro ownership to be transferred to another owner for the economic benefit of Manitoba Hydro as soon as an appropriate opportunity can be developed.

Decrease in Capital Cost Estimates for U.S. Portion of 750 MW Interconnection

Recent more detailed cost estimates are indicating that the costs of the U.S. portion of the 750 MW interconnection will be less than originally estimated. This would improve the economics of the interconnection in Pathways 4 and 5.

Other Potential Firm Export Sales in the U.S. and Canada

The MP and WPS sales will only utilize part of the 750 MW export capacity of the 750 MW interconnection leaving capacity available for long-term export contracts for additional sales to Wisconsin, Minnesota and to other utilities. In addition, early Conawapa G.S. would enable the extension of the 375/500 MW NSP sale which currently ends in 2025. This extension requiring advancement of Conawapa G.S. would benefit the economics of the 750 MW interconnection plans; the 250 MW plans would not benefit as much because the 250 MW interconnection would be already utilized by the 250 MW MP Sale.

In addition, Manitoba Hydro is in active negotiations with SaskPower regarding long-term export sale possibilities up to 500 MW, along with Saskatchewan interconnection transmission additions required to enable the sale. A sale would require early Conawapa G.S. (e.g. in-service prior to 2030). The excess power from Conawapa G.S. would also be exported over the U.S. 750 MW interconnection and improve its economics.

Integrated Comparisons of the Development Plans – Multiple Account Analysis

The results of a multiple account benefit-cost analysis (MA-BCA) are presented in ***Chapter 13 - Integrated Comparisons of Development Plans - Multiple Account Analysis***. The analysis compares Manitoba Hydro's Preferred Development Plan to a plan with a smaller interconnection and less firm export sales (K19/Gas 24/250MW), and two plans without a new interconnection and firm export sales, one with Keeyask (K22/Gas) and one assuming All Gas to meet growing Manitoba requirements.

MA-BCA is a variant of traditional cost-benefit analysis. It extends Manitoba Hydro's economic evaluation of the different plans to take into account consequences and net benefits or costs for customers, taxpayers, workers and the economy, the environment, affected communities and Manitobans generally. These net benefits and costs are not reflected in the NPV of the different plans from the perspective of Manitoba Hydro and its project partners. The MA-BCA is intended to assist the NFAT panel address the question of the overall socio-economic benefit of the preferred and alternative plans, and more specifically the relative advantages and trade-offs they entail.

MA-BCA recognizes that not all consequences can be monetized in order to calculate a 'bottom line'; as well there are important distributional consequences that need to be considered in the assessment of the relative advantages or disadvantages and trade-offs that the different plans entail. The results of the MA-BCA are presented under a disaggregated set of evaluation accounts:

- market valuation
- customers
- government
- Manitoba economy
- environment
- social
- risk.

Table 5 presents a summary of the findings based on the NFAT Reference Scenario set of assumptions, with monetized values reported relative to the Preferred Development Plan (positive values indicating a net advantage relative to the Preferred Development Plan and negative values a net cost disadvantage).

Table 5 SUMMARY OF MULTIPLE ACCOUNTS ANALYSIS - REFERENCE SCENARIO ASSESSMENT

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Market Valuation • Net revenues (cost) to MH and partners	--	17.0	(270.5)	(654.1)
Customer Account • Cumulative rate increase	Preferred Development Plan has the lowest projected rate increases over long-term, with the highest projected rate increases in first 20 years.			
• Reliability	Preferred plan and to lesser extent the alternative with the smaller interconnection provides greater load carrying capability, lower expected loss of unserved energy and greater ability to manage extreme drought			
Government • Incremental revenues net of costs/risk	--	(353.5)	(395.9)	(674.2)
Manitoba Economy • Employment net benefits	--	(123.7)	(150.0)	(260.3)
Environment • Manitoba GHG external cost	--	(208.6)	(174.3)	(320.3)
• Global GHG impact	Preferred plan and to lesser extent the two plans with Keeyask would contribute to a reduction in global emissions by displacing thermal generation in US.			
• Manitoba CAC damage cost	--	(8.6)	(7.1)	(13.3)
• Residual biophysical	Aquatic and terrestrial impacts with hydro projects in preferred plan and plans with Keeyask; subject to detailed environmental hearings, residual effects and local external cost expected to be relatively small with initial design, extensive mitigation, monitoring, compensation and benefit-sharing arrangements.			
Social • Partner net return	Significant net returns from up to 25% interest in Keeyask and income benefits from Conawapa in preferred plan; significant benefits from up to 25% interest in two alternatives with Keeyask, greater with new sales and interconnection.			
• Community impacts	Wide range of potential impacts on local employment and business; population, infrastructure and service; social and community well-being; owners of land needed for rights of way and easements; major commitments and plans to minimize adverse residual effects with extensive mitigation, monitoring, compensation and partnership arrangements.			
• Other Manitoba	Potentially significant bequest value from the hydro assets remaining at end of planning period; greatest with preferred plan and to a lesser extent in the alternatives with Keeyask.			
Overall Monetized Net Benefit (Cost)	**--**	**(677.4)**	**(997.4)**	**(1922.2)**

(2014 Present Value in millions 2014$)

Overall, the main conclusions of the MA-BCA are as follows:

- Developing Keeyask G.S. to meet domestic load offers significant net benefits relative to the All Gas plan not only for Manitoba Hydro but also more broadly to society as a whole; it offers significant tax, employment, GHG and social benefits that go beyond the benefits to Manitoba Hydro.
- Plans that include a new interconnection offer significant net benefits to those that don't. They significantly enhance the net benefits for Manitoba Hydro and its partners.
- The alternative with the 250 MW interconnection and the development of Keeyask G.S. but not Conawapa G.S. offers the same expected net benefit to Manitoba Hydro and its partners as the Preferred Development Plan, without the short- to medium-term rate trade-off that the Preferred Development Plan gives rise to. At the same time it doesn't offer the same long-term legacy value or upside potential as the Preferred Development Plan. Nor does it offer the long-term rate, tax, employment, GHG and social benefits as the Preferred Development Plan.
    - The Preferred Development Plan offers the lowest rate impacts for the long-term and significantly greater benefits to society as a whole than the smaller tie alternative. It does, however, require higher rate increases in the short- to medium-term than the other plans. The more weight one places on the broader public interest consequences and the longer term effects, the more one would favour this plan.

Conclusions – Which Development Plan and Pathway to Choose

Planning for Uncertainty

The economic, financial and multiple accounts evaluations by necessity considered mainly plans with specific choices of generation options and timing. For example, the Preferred Development Plan was put forward as "Keeyask ISD 2019 followed by Conawapa ISD 2025," while the Natural Gas Plan was put forward as "Natural Gas Generation in 2022 followed only by Natural Gas Generation in subsequent years." Clearly, in reality, such choices are not rigidly frozen but rather will respond over time to evolving conditions and societal expectations.

Load growth, Power Smart plans, new export contracts, natural gas price forecasts, export price forecasts, capital cost estimates, retirement of existing gas generation and other parameters will be continually monitored and reviewed. There are certain circumstances in which the passage of time will make updated information or learnings available, which can reduce uncertainty and allow decisions to be made more confidently in the future than if they were made now. For example, deciding the start of Conawapa construction in 2018 for a 2026 ISD would have 4 years less uncertainty than if that decision were made in 2014, more than 12 years in advance of the ISD.

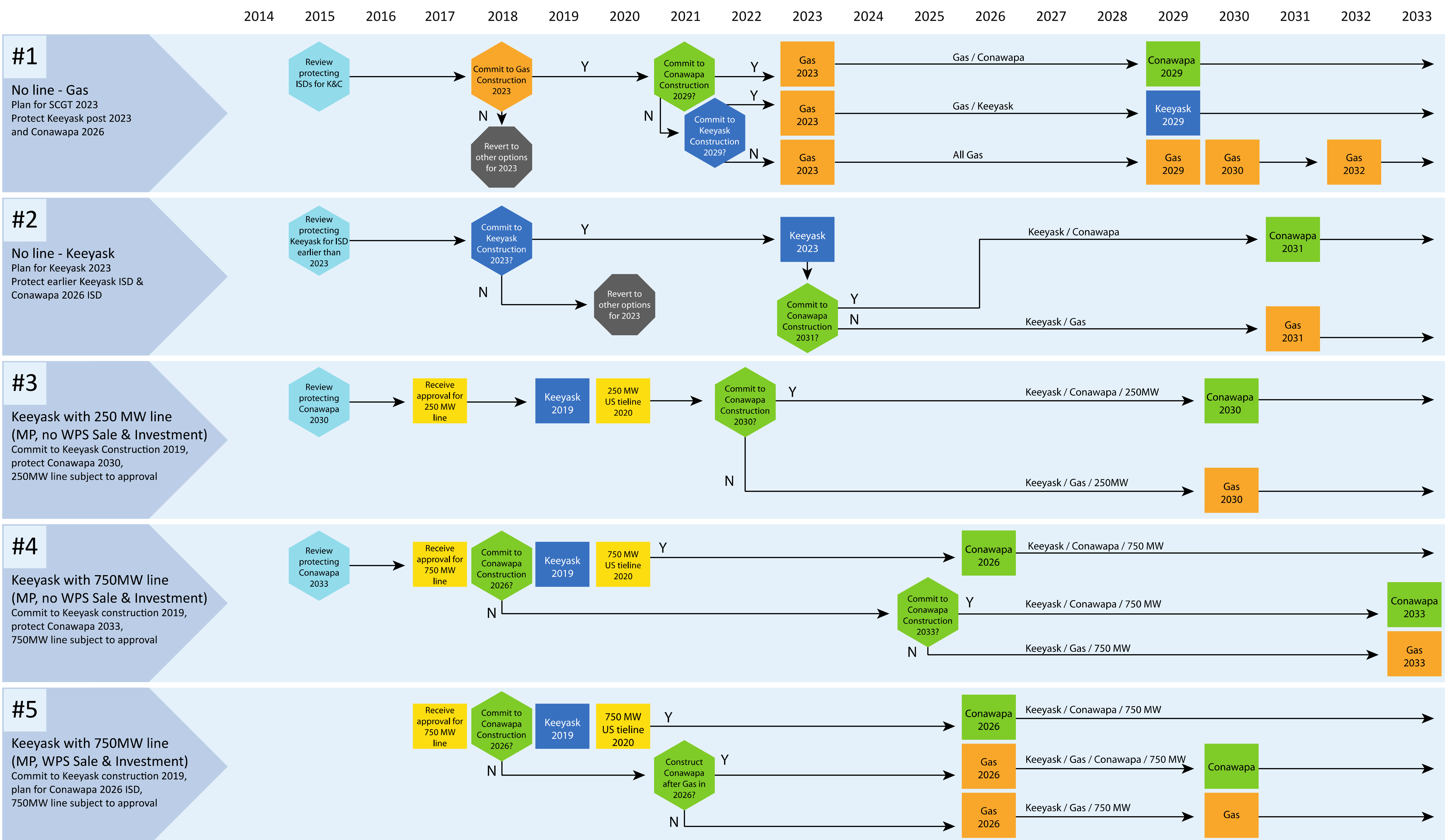
Alternative Development Pathways

The long-term flexibility to respond to events or the trajectory of critical parameters as they unfold over time is fundamental to managing risks and dealing with uncertainties. It is useful to consider the evaluations not as leading to a choice between fixed plans with fixed in-service dates, but rather a choice between different pathways. The five general approaches for "development plan implementation pathways" identified here are representative of the choices to be decided upon as the next step in Manitoba's electricity future:

- Pathway 1 Gas Only, No New Interconnection, No New Exports – domestic load only
- Pathway 2 Keeyask 2023, No New Interconnection, No New Exports – domestic load only
- Pathway 3 Keeyask 2019, 250 MW Interconnection, Small Export - 250 MW MP sale and 125 MW NSP extension; no WPS sale
- Pathway 4 Keeyask 2019, 750 MW Interconnection, Small Export - 250 MW MP sale and 125 MW NSP extension; no WPS investment in interconnection and no sale
- Pathway 5 Same as Pathway 4 but with Large Export - e.g. also includes WPS sale and investment in interconnection.

Figure 5 chronologically presents the decisions and options associated with each pathway.

Figure 5 PATHWAY DECISION TREE - ISDs BASED ON 2013 LOAD FORECAST AND RELATED ASSUMPTIONS



In-depth comparisons of the five pathways are contained in ***Chapter 14 - Conclusions*** of the submission. The Preferred Development Plan is included within Pathway 5 if the WPS sale is successfully concluded and in Pathway 4 if it is not. Both cases assume Keeyask in 2019, the 750 MW interconnection and the MP and NSP sales. Both cases provide the flexibility, if conditions change, to defer Conawapa or replace it with natural gas generation.

The use of pathways recognizes the reality that plans are continuously modified over time. A current example of such a modification is that the Conawapa planned ISD was recently deferred from 2025 to 2026 in association with a drop in the Manitoba load growth forecast.

In the future, if the Preferred Development Plan were adopted but then natural gas and export prices were found to be following a low price trajectory, Conawapa could be deferred or could be completely displaced with other new generation such as natural gas. Similarly, Conawapa could be delayed if there were a major reduction in forecast load growth or a major increase in power savings resulting from DSM.

Overall Conclusions

The economic, financial, multi-account and pathways analyses lead to the following broad conclusions in regard to the components, timing, expected impacts and risk/reward characteristics of Manitoba Hydro's Preferred Development Plan.

Components of Preferred Development Plan

- A plan comprising only natural gas additions is **not** attractive, economically, financially or environmentally.
- Plans which include the **new transmission interconnection and related hydro export sales** provide the highest expected economic and financial benefits in the long-term compared to plans with no new interconnection, whether they involve hydro or gas generation.
- **Keeyask** is the best option to meet the electricity supply gap in the early 2020s because it provides clean renewable energy and superior economic returns compared to natural gas

generation. Also, Keeyask's pre-construction phase is already underway and is supported by the in-vicinity Aboriginal communities.

- **Conawapa** is the more economic supply option after Keeyask in cases in which a large (750 MW) interconnection is installed. If the interconnection is smaller (250 MW), natural gas generation is more economic.
- **DSM** could be doubled or tripled without affecting the conclusions on the favourability ranking of plans with these components.

Timing

- Keeyask would come into service in 2019. The date could be deferred until 2023 if a decision were made not to proceed with the U.S. interconnection or related new export sales and net load did not increase. However, such a decision would give up substantial benefits and close the door to new export opportunities and a new interconnection for the foreseeable future.
- Conawapa could come into service at the earliest in 2026/27. Based on the 2013 load forecast and other 2013 assumptions, the date could be deferred to 2033 if the WPS sale or other attractive new export sales are not concluded. Activities would continue to protect an ISD for Conawapa as early as 2026, but conditions which are pertinent to this schedule will be continually monitored to determine if such continued investments are worthwhile and, ultimately, to determine if Conawapa should be constructed, for what ISD and if protection of an early ISD is warranted.
- The new interconnection is expected to receive U.S. approvals by no later than 2017 before Conawapa construction must be committed for a 2026 ISD.

Risk and Reward

- The Preferred Development Plan demonstrates greater economic variability (greater upside and downside) than plans which do not include new export sales and which are focused only on serving Manitoba needs.

- Financial resources may be strained in the medium-term if Conawapa is constructed for 2026 and if adverse conditions occur in the same time frame (e.g. higher capital costs, lower energy prices, low regional load growth, drought etc.).
- However, financial and other risks are mitigated by the ability to defer Conawapa or substitute gas generation if considered prudent to do so over the next few years.
- Greater variability also brings the possibility of higher reward. If energy prices are higher than forecast or even evolve as currently expected, the long-term benefits of the Preferred Development Plan could be substantially increased.
- Plans with the 750 MW interconnection provide overall the most flexibility to manage risks such as higher or lower load growth, uncertainty in level of future DSM, severe drought and increases and decreases in river flows due to climate change and to take advantage of future opportunities such as other export sales in addition to or instead of WPS.

Expected Benefits

Under expected conditions, the plans which include Keeyask 2019, 750 MW interconnection, new export sales, and Conawapa are generally expected to have the following positive impacts relative to other alternatives:

- Lower long-term customer rates (though generally higher during upcoming periods of construction).
- Supports Manitoba Hydro’s long-term fiscal health with higher levels of fixed assets and retained earnings, which provide enhanced protection against adverse events such as severe drought.
- Highest level of system reliability (e.g. to deal with generation or major transmission outages or unexpectedly high load peaks) and energy security (e.g. to deal with unexpectedly severe droughts or unexpectedly high energy consumption).
- Greatest number of jobs and socio-economic benefits.
- Lowest GHG emissions and greatest support for Manitoba Clean Energy Strategy.
- Benefits to Aboriginal communities in the vicinity of the new dams.

- Use of Manitoba's renewable hydro resources rather than carbon-based energy from out of province.
- Largest payments to the Province through taxes and fees.
- Provision of an infrastructure legacy for future generations.

In summary the Preferred Development Plan as discussed on page 1 of this ***Executive Summary*** is preferred because it offers the greatest flexibility and largest range of potential benefits of any of the options examined.

Implementation and Risk Management Plan

Manitoba Hydro has a well-developed and comprehensive approach to undertake the plan and manage the risks of the Preferred Development Plan. This approach includes an implementation schedule containing portfolio risks, potential impacts and decision points. This schedule and a full range of risk mitigation measures are discussed throughout the submission and, in particular, in ***Chapter 15 – Implementation and Risk Management Plan for Preferred Development Plan***.