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NFAT Review: Green Action Centre Evidence on Fuel Switching, DSM and Wind

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Table of Contents

Table of Tables

1 Introduction

On August 16, 2013, Manitoba Hydro ("MH" or "Hydro") filed an application (the "Needs For and Alternatives To" (NFAT) report) with the Manitoba Public Utilities Board for approval of its "Preferred Development Plan" for the development of Manitoba's electricity system. This Preferred Plan includes:

- Development of the 695 megawatt (MW) Keeyask hydroelectric project, with an in-service date of 2019
- Development of the 1,485-MW Conawapa hydroelectric project, with an earliest in-service date of 2026 (decision still to be made)
- Development of an additional 750-MW intertie between Manitoba, Minnesota and Wisconsin
- New export sales contracts with Minnesota Power (250 MW) and Wisconsin Public Service (300 MW), and expansion of existing approved sale with Northern States Power (125 MW)

The Green Action Centre ("GAC") was granted Intervener Status in this matter, and the following issues identified by GAC were determined to be within the scope of the proceedings:

(a) Forecasts and risks associated with domestic load, export commitments and export pricing;
(b) Use of Demand Side Management and alternative energy initiatives;
(c) Marginal costs of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives including DSM; and
(d) Alternatives to Manitoba Hydro's PDP together with integration into a diversified portfolio and consideration of such contributions to Risk Management.[1]

This report considers a handful of issues that fall within this scope. Those issues are:

- The treatment of fuel switching and fuel choice between gas and electricity for space and water heating.
- The potential scale of DSM-driven reductions in MH energy load and peak demand and the effect of aggressive DSM programs on the need for new generation resources.
- The role of wind energy as an alternative energy source of Manitoba Hydro.

Our major conclusions are as follows:

- Hydro's load forecast includes substantial new electric load, due to the use of electricity where natural gas would be less expensive for the customer, Hydro, the province, and the environment. Hydro should be reducing that inefficient electricity usage, to reduce costs, free up electricity for export and reduce global greenhouse gas emissions.

[1] Manitoba Public Utilities Board, *Order No. 67/13: NFAT Procedural Order on Intervener Status*, June 11, 2013, p. 14.

- Experience in other jurisdictions indicates that aggressive DSM programs can reduce electric loads by 1.5% of sales each year. With that level of DSM load reductions, no new generation resources would be required for domestic loads. Existing resources could support the contracted and proposed exports, with the exception of small shortages of capacity (less than 70 MW) in five years in the early 2030s and of energy (less than 115 GWh) for three years starting 2022/23. Additional generation resources may be justified to enable additional exports, including the 500 MW sale currently under discussion with Saskatchewan for some time after 2020.
- Hydro has significantly overestimated several components of the cost of wind, including future capital costs, construction period, operating life, fixed O&M, and integration costs. With these factors corrected, the likely cost of wind energy is comparable to, or lower than, that of MH's proposed hydro plants. Wind has several advantages over the proposed hydro plants, including shorter lead time, a higher percentage of energy that is firm, and independence of energy output from drought conditions. With a realistic expected cost of wind, it is quite possible that a Plan could be constructed involving wind and interties that has a lower expected cost than MH's Preferred Plan, with lower risk.

The following three sections deal with those three topics. The first two sections, on fuel choice, load and capacity, were prepared by Resource Insight Inc., and the final section, on the role of wind, was prepared by Power Advisory LLC.

2 Fuel-Switching and Fuel-Choice as Planning Resources (Resource Insight Inc.)

One aspect of integrated resource planning is the choice of energy sources at the customer end use. Where electricity is environmentally and economically preferable to other energy sources (as may be the case for transportation, compared to petroleum-fueled internal combustion engines), electric use should be encouraged and the electric utility should be planning resources to service that demand. Where electricity is more expensive and more environmentally damaging than the alternatives, electric use should be discouraged and electric utility not be acquiring resources for load it should not be serving.

In the case of Manitoba Hydro, the use of electricity for space and water heating, where natural gas is available as an alternative, wastes a valuable resource that could otherwise be exported to increase Manitoba revenues and reduce emissions of CO_2 and other pollutants.

2.1 MH analyses of fuel-choice economics

After some years of pressure from the Board and other parties, MH filed a report, "Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba" (the "Fuel-Switching Report") as Appendix 26 in its General Rate Application review for 2011/12 and 2012/13.[2] Hydro defined fuel switching as including

> Customers in existing homes who replace their natural gas space and water heating equipment with electric equipment when it reaches the end of its life; [and] Customers (or homebuilders) building new homes who build where natural gas service is available, but instead choose to install electric heating equipment. (Fuel-Switching Report at 13)

The Fuel-Switching Report considered (in various levels of detail) choices among four options for space heating—electric resistance (furnace or baseboard), ground-source heat pump with a 2.5 seasonal coefficient of performance, or a high-efficiency gas furnace—and five options for water heating—electric resistance and desuperheater units and natural-gas side vent, natural-vent, and tankless units.[3]

The report concluded that switching to electricity for space and water heating has consistently adverse impacts from every perspective:

- the resident using the service,
- the electric and gas utilities,
- the financial flows out of Manitoba (provincial leakage), and
- the global environment.

Specifically, Hydro found that choosing electric resistance or a geothermal heat pump over a gas furnace, or an electric water heater over a gas water heater, increases the costs to the customer, to

[2] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/Appendix_26.pdf

[3] The report mentions hydronic heating once, but provides no analysis.

electric customers as a whole, and to other gas customers. The report further concluded that such fuel switching increases carbon emissions and (with the possible exception of the heat pump), the net cash flow out of Manitoba (Fuel-Switching Report at 37).

From every perspective and every application considered in the Fuel-Switching Report, the report found that selecting electricity over gas would be undesirable by every measure. Yet the historical data indicate that new dwellings have been adopting electric heat, as summarized in Table 2-1.

Table 2-1: Electric Heating Penetration with Gas Available, New Dwellings 2005-2009

Single Detached Winnipeg	3.3%
Single Detached Other Gas Areas	63.4%
Multi-Attached	56.3%
Individually Metered Apartments	87.8%
Overall	48.3%
Excluding Winnipeg Single Homes	70.4%

Source: GAC/MH I-052

Aspects of the assessment in the Fuel-Switching Report are supported by the Focus on What Matters Most: Manitoba's Clean Energy Strategy, which describes electric space and water heating as "not the best solution" and touts the benefits of switching away from electricity use, including "lower energy costs, new local jobs, freeing up more electricity for Manitoba hydro exports." (Appendix 1.5, at 30) While the strategy emphasizes the benefits of renewable energy and geothermal heat pumps, conversion to gas has similar benefits.[4]

2.2 MH Projections of Future Fuel-Switching Choices

2.2.1 The Fuel-Switching Report

Despite the failure of electric space and water heating on all of MH's tests, the Fuel-Switching Report forecast significant shifts of energy usage from gas to electricity, including

- By 2030/31, about 48,000 residential gas heating customers (or 9% of MH residential customers) switching to electric space heat,
- By 2030/31, about 146,000 gas-fired residential water-heaters (about 26% of residential customers) switching to electricity.
- Hundreds of commercial customers switching gas space and water heating to electricity.

[4] The Strategy also appropriately promotes conservation of natural gas. Unfortunately, the Strategy focuses on greenhouse gas emissions in Manitoba, rather than the effects of energy use in Manitoba on regional emissions.

- “Virtually 100% of the new home market … installing electric water heaters.” (Fuel-Switching Report at 4) “For water heating, a trend towards increased use of electric water heaters has been evident and is forecast to continue into the future. The new home market is effectively 100% transformed, with almost all new homes located within natural gas serviced areas now being constructed without chimneys and using electric hot water heaters.” (ibid at 39)

- “For space heating, a slight trend towards more customers using electricity has been observed. This trend was reflected in Manitoba Hydro’s 2011 Energy Forecasts where a drop of approximately 3% in the use of natural gas for space heating is forecast.” (Fuel-Switching Report at 39)

- As much as 11% of the growth in Net Firm Energy requirements from 2011/12 to 2020/31, would be due to fuel switching from natural gas to electricity (Fuel-Switching Report at 27).

2.2.2 The 2012 Load Forecast

In the 2012 load forecast, MH repeated both its conclusions regarding the poor economics of electric heat and its projections of continuing increases in gas saturation:

> Under current natural gas prices, it is cheaper to heat one’s home with natural gas than with electricity. This forecast assumes that natural gas will retain its price advantage over electricity over the next 20 years. The forecast is that by 2031/32, 234,363 or 40.6% of Residential Basic customers will heat their home with electricity. (Appendix C at 55)

The space-heating saturation forecast for 2031/32 was a 13% increase from the 36% saturation in 2012/13.

> New homes are now primarily built with electric water tanks rather than natural gas water tanks regardless of their space heat fuel choice. In existing homes, as standard and mid-efficiency gas furnaces are being replaced with a high efficiency gas furnace, some homeowners are choosing to replace their existing natural gas water heaters with electric water heaters. (Appendix C at 55)

MH projected that the saturation of water heating would rise from 47% to 69%, equivalent to all new homes adopting electric water heating and 21% of existing homes with gas hot water switching to electric hot water. (Appendix C Table 14)

2.2.3 The 2013 Load Forecast

In the 2013 load forecast, MH dialed back the 2012 projections of electric space and water heating, based on the assumption that some unspecified initiatives would slow the rush from gas to electricity.

> The percentage of newly constructed homes choosing electric space heat was…adjusted to reflect Manitoba Hydro’s initiatives being undertaken to reduce the number of customers choosing electricity for space and water heat. (Appendix D at 60)

MH still projects substantial penetrations of electricity for space heating and very high penetration of electricity for water heating where gas is available, and substantial conversions of water heating from gas to electricity.

> An increase in average use per [Residential] customer adds 0.3% to the growth and is primarily due to increased use of electric space heating and electric water heating in homes. (Appendix D at i)
>
> Under current natural gas prices, it is cheaper to heat one's home with a high efficiency natural gas furnace than with electricity. This forecast assumes that natural gas will retain its price advantage over electricity over the next 20 years. The forecast is that by 2032/33, 221,868 or 39.3% of Residential Basic customers will heat their home with electricity….
>
> New homes are now primarily built with electric water heaters rather than natural gas water heaters regardless of their space heat fuel choice. In existing homes, as standard and mid-efficiency gas furnaces are being replaced with a high efficiency gas furnace, some homeowners are choosing to replace their existing natural gas water heaters with electric water heaters. (Appendix D at 54)

While MH promises some reductions in projected rates of switching *to* electricity, MH has not provided any analysis or estimates of fuel-switching from electric to gas, despite the financial and environmental benefits of gas.

2.2.3.1 Space-Heating Projections

While MH's forecast assumes that it can discourage almost all new electric heat in Winnipeg, it assumes that it can only reduce the penetration of electric heat by about 60%, and that even that limited result would take about a decade, as summarized in Table 2-2. Due to the delay in effectiveness of the initiatives, MH projects that it will be able to avoid less than half the new electric heat outside Winnipeg.

Table 2-2: % New Single Detached Homes Installing Electric Heat

	Winnipeg		Other Gas Areas	
Fiscal Year	Without Initiative	With Initiative	Without Initiative	With Initiative
2013/14	3.3%	3.2%	63.4%	61.8%
2014/15	3.3%	3.0%	63.4%	59.4%
2015/16	3.3%	3.0%	63.4%	57.8%
2016/17	3.3%	2.9%	63.4%	55.4%
2017/18	3.3%	2.5%	63.4%	50.6%
2018/19	3.3%	2.1%	63.4%	43.4%
2019/20	3.3%	1.7%	63.4%	37.2%
2020/21	3.3%	1.5%	63.4%	33.2%
2021/22	3.3%	1.2%	63.4%	30.0%
2022/23	3.3%	0.9%	63.4%	26.1%
2023/24	3.3%	0.7%	63.4%	23.8%
2024/25	3.3%	0.5%	63.4%	23.8%
2025/26	3.3%	0.4%	63.4%	23.8%
2026/27	3.3%	0.3%	63.4%	23.8%
2027/28	3.3%	0.3%	63.4%	23.8%
2028/29	3.3%	0.2%	63.4%	23.8%
2029/30	3.3%	0.2%	63.4%	23.8%
2030/31	3.3%	0.1%	63.4%	23.8%
2031/32	3.3%	0.1%	63.4%	23.8%
2032/33	3.3%	0.1%	63.4%	23.8%

Source: PUB/MH I-253a Table 1

In contrast, MH projects that it can eliminate conversions of gas-heated single-family homes to electricity by 2017 (PUB/MH I-253a Table 2)

2.2.3.2 Water-Heating Projections.

MH has only slightly moderated its projection that essentially all new construction will use electricity for water heating, as shown in Table 2-3.

Table 2-3: MH Projection of Electric Water Penetration in New Single Detached Construction, Gas Available

Forecast Year	Electric Water Total	Other Water Total	Electric Penetration
2013/14	3,369	24	99.3%
2014/15	3,373	45	98.7%
2015/16	3,373	45	98.7%
2016/17	3,347	69	98.0%
2017/18	3,316	115	96.6%
2018/19	3,273	185	94.7%
2019/20	3,246	230	93.4%
2020/21	3,255	231	93.4%
2021/22	3,256	231	93.4%
2022/23	3,248	230	93.4%
2023/24	3,231	229	93.4%
2024/25	3,206	227	93.4%
2025/26	3,176	225	93.4%
2026/27	3,144	223	93.4%
2027/28	3,109	220	93.4%
2028/29	3,069	217	93.4%
2029/30	3,027	214	93.4%
2030/31	2,986	211	93.4%
2031/32	2,948	209	93.4%
2032/33	2,913	206	93.4%

Source: GAC/MH I-062

By 2032/33, MH projects the addition of almost 64,000 water heaters, which would increase electric use by about 223 GWh.

As shown in Table 2-4, MH projects that significant percentages of existing gas water heaters will be replaced with electric water heaters, apparently as the tanks wear out.

Table 2-4: MH Forecast of Water-Heater Conversions, Single-Family Detached Homes

Forecast Year	Gas to Electric Water Heat Conversion	Non-electric Water Heaters Replaced	% of Gas Water Heaters Converted on Failure
2013/14	2,833	12,795	22.1%
2014/15	2,695	12,576	21.4%
2015/16	2,471	12,381	20.0%
2016/17	2,252	12,207	18.4%
2017/18	2,038	12,058	16.9%
2018/19	1,831	11,931	15.3%
2019/20	1,631	11,828	13.8%
2020/21	1,481	11,741	12.6%
2021/22	1,375	11,664	11.8%
2022/23	1,272	11,595	11.0%
2023/24	1,214	11,535	10.5%
2024/25	1,196	11,477	10.4%
2025/26	1,177	11,422	10.3%
2026/27	1,159	11,368	10.2%
2027/28	1,141	11,318	10.1%
2028/29	1,123	11,270	10.0%
2029/30	1,105	11,232	9.8%
2030/31	1,089	11,199	9.7%
2031/32	1,073	11,167	9.6%
2032/33	1,057	11,137	9.5%

Sources: GAC/MH I-064 and GAC/MH I-066

By 2032/33, MH projects the conversion of over 31,000 water heaters, which would increase electric use by about 109 GWh.

MH has not provided such detailed data for the other housing categories, but the data in GAC/MH I-060 is consistent with about 3,300 existing multi-attached units switching to electricity and all of the 7,900 new such units using electricity. For apartments, GAC/MH I-060 is consistent with a 31% penetration of electric water, adding another 6,200 electric water heaters.

While we do not have comparable data for commercial fuel-switching choices, the Fuel-Switching Report (at 27) indicated that MH expected additional load growth due to increases in commercial electric space and water heating.

2.3 MH's Explanation of the Trend Towards Uneconomic Fuel Choices

The Fuel-Switching Report explained electricity's nearly complete capture of water-heating load in new single-family homes, even where gas is available, as follows:

> This shift from using natural gas water heaters is being driven primarily by economics, as the cost of installing natural gas water heaters has risen substantially due to new designs incorporating safety measures and due to the adoption of more energy efficient side-vented hot water tanks. In addition to the increased capital cost of natural gas hot water tanks, the gap in operating costs between an electric and natural gas hot water tank narrowed substantially during the past decade due to increased natural gas prices. More recently natural gas prices have fallen dramatically and the price gap in operating costs is again widening, The impact on customer preferences for natural gas hot water tanks at this time are uncertain; however, it is doubtful that homebuilders will be promoting the use of natural gas hot water heaters due to the higher capital cost associated with these units. (Fuel-Switching Report at 39)

In short, MH explains that developers have adverse incentives to install electric space and water heating, because (1) electric equipment is less expensive and (2) the developer can charge buyers the same price for the cheaper, inferior electric system or the superior gas system.

In the last GRA, Hydro listed the market distortions that may lead customers to the globally worse and more expensive solution as follows:

> Customer choice may be influenced by a variety of factors which may impact a customer's decision on fuel use for water/space heating, including the customer's expectations with regards to future prices for electricity and natural gas, estimated or quoted capital cost of implementing the options, expected maintenance costs, and a customer's values related to the environmental impacts of the decision. Further, a customer may not make a decision based on an economic assessment over the life of the system (e.g. the customer may be considering moving and therefore may not expect to realize the payback of an investment). (GRA GAC/MH II-16a)

MH repeats these explanations in discovery in this proceeding:

> The initial installed cost of electric heating systems is less expensive than that of natural gas systems. Some customers do not consider total cost of ownership (i.e. capital cost plus operating cost), and as such, may choose an electric heating system. In the new home market, the heating system decisions are made by the homebuilder when homes are built on speculation. A lower initial cost allows the homebuilder either to sell the home at lower price or the opportunity to make more profit per home. In addition, some builders have also indicated the additional operational benefit of not needing to coordinate additional work crews associated with natural gas. (GAC/MH I-077)[5]
>
> Homebuilders in Manitoba primarily install electric water heaters because this is the most economic option for the homebuilder and as such, it allows the homebuilder to keep the base cost

[5] This response also lists various types of information problems (about costs, environmental effects and local development) and safety perceptions.

> of the home lower, thereby the homebuilder's competitive position in the new home market. (GAC/MH I-079)[6]

In short, the customer may not have adequate information on price forecasts, maintenance costs, effect on resale value, or the environmental effects of the fuel choice. The customer may face financial constraints; be gouged or misled by vendors or contractors; be denied choices by developers; and have a short planning horizon.

MH also suggests that consumers who have gas equipment may be led into choosing the more expensive electric option by an excessive focus on capital costs, "the customer's personal financial situation," and bad advice from contractors:

> The economics for the customer depends upon their specific circumstances and whether the customer is considering total costs (capital and operating) or simply considering the capital cost. In many cases, customers might be primarily influenced by the upfront costs. In cases where customers replace their conventional natural gas furnaces with high efficiency models, the existing chimney may need to be sleeved or adjusted at an additional cost of approximately $550 to adequately vent a conventional natural gas water heater. If required, this will increase the cost of the installation diminishing the overall net benefit of choosing natural gas water heating.
>
> The customer will assess the choices based upon their individual circumstances, including the age and condition of their existing water heater and the customer's personal financial situation. In some situations, contractors may encourage customers to install an electric water heater rather than assessing the need for adjusting the venting or installing a more costly sideventing natural gas water heater. (GAC/MH I-071)

Since the Fuel-Switching Report found that gas water heating was about $1,054 per household less expensive than electric water heating under "average" conditions (Fuel-Switching Report at 24), reflecting some combination of conventional and side-vented water gas heaters (with $850 incremental capital costs) would be less expensive even for the unknown fraction of customers requiring the $550 for sleeving or adjustment.

MH's discussions of the drivers of fuel-switching and fuel-choice decisions appear to closely follow the market barriers that traditionally justify DSM programs and other interventions in consumer energy choices: lack of information, adverse incentives for developers and contractors, financial constraints and a short planning horizon.

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[6] MH adds the less plausible explanation that "A conventional natural gas hot water tank is not considered an option as it would require a chimney which would reduce the useable square footage available to the homeowner or it would require constructing a large home to accommodate the additional square footage needed for the chimney." (GAC/MH I-079) Given the small cross-section of a modern chimney, this explanation seems far-fetched.

2.4 Potential Responses to the Fuel-Choice Market Failures

On its face, the Fuel-Switching Report and MH's subsequent analysis clearly indicate a serious market failure, which should be addressed through a combination of rate design, DSM programing, and terms and conditions for new and expanded service.

2.4.1 Hydro's Planned Initiative

Even though MH acknowledges that electric space heating (and in many cases electric water heating) increase costs to the customer, to both the gas and electric utilities, the province and to the environment, "Manitoba Hydro's current strategy is not to promote natural gas over electricity." (PUB/MH I-253b) Hydro does not flinch from promoting higher levels of energy efficiency to reduce costs to the consumer, the utility, the province, and the global environment; it should not hesitate to advocate for the appropriate choices in fuel sources.

Hydro's description of its "initiative" to reverse the uneconomic choice of electricity as a space- and water-heating fuel indicates that Hydro intends very limited efforts, limited to education:

> The Corporation's strategy is to educate customers on their fuel choice options so customers make informed decisions. It is expected informed customers will generally make rational decisions and the impact of this approach will result in more customers using natural gas for heating applications.
>
> Manitoba Hydro's initiative to educate customers is through its Heating Education Campaign, which takes a multi-faceted approach to educating the several stakeholders involved in the fuel-choice decision. The campaign targets homeowners, heating contractors, homebuilders and land developers.
>
> The focus of the Heating Education Campaign is to increase awareness and understanding of the total lifetime cost of natural gas, electricity and geothermal heating systems and to provide customers with the tools to effectively assess the most economic system which best meets their needs and circumstances. …
>
> Beginning in 2012, information sessions were held throughout natural gas available areas of the Province for heating contractors, homebuilders and land developers to highlight the total lifetime costs of a heating system and the implications the heating system choice has on a customer's energy bill. Information sessions will continue to be provided…as deemed appropriate.

> Educational materials have been developed with separate messaging created to target customers building a new home and those customers with existing heating systems. (PUB/MH I-253b)[7]

Information-only DSM programs are rarely successful, without technical assistance and financial incentives. If Hydro's explanation of the drivers for electric space- and water-heating is correct, its announced strategy for the Heating Education Campaign entirely misses the point. According to Hydro,

- The heating contractors, homebuilders and developers, as well as many customers, are concerned mostly about first costs. (GAC/MH I-071, I-077, I-079)
- Some builders prefer to avoid the need to schedule gas installers (probably also to reduce first costs). (GAC/MH I-077)
- Contractors promote electric water heating because that avoids the need to assess venting options. (GAC/MH I-071)
- Some customers assume that their use of electricity for heating protects the global environment, even though Hydro understands that wasting electricity on domestic heat loads reduces the availability of that energy to back down higher-emission coal and gas-fired generation.

The developers, builders and contractors probably know that gas is less expensive for their customers, but it requires more effort and investment for the professionals. Simply telling them what they already know will not be likely to change their behaviour. The Hydro campaign does not address at all the confusion of customers (and probably some professionals) regarding the environmental effects of electric space and water heating. Nor does it appear to address commercial customers. Hydro's heating campaign is unlikely to have even the modest benefits it projects.

On the other hand, a vigorous promotion of gas heat should be able to reverse the slide towards electric space and water heat and convert some existing electric loads to gas, if MH adds to the economic information program the following components:

- incentives to offset the self-interested preference of developers, builders and contractors for electric equipment over gas;
- recommendation of fuel-switching through the same PowerSmart mechanisms and with the same emphasis as insulation, efficient appliances and lighting, for residential and commercial buildings; and

[7] The response to PUB/MH I-253b touts the "Corporate 'Heating' webpage including …a heating cost comparison calculator and a heating system education video." The calculator requires the customer to gather data on equipment costs, and the video simply explains geothermal heating, which it claims uses primarily "the Earth's renewable energy." (By that standard, other heat pumps, including air conditioners and refrigerators, also use renewable energy.) Few customers are likely to select gas based on either of these tools.

- provision of data on the environmental and province-wide benefits of gas heat compared to electric heat.

2.4.2 Rate Design

The tendency for customers to make choices that increase emissions, as well as costs to the Province as a whole, can be reduced by implementation of inclining-block residential rates, especially in the winter heating season. In implementing those rates, the Board should also institute initiatives to:

- Mitigate the burden on low-income customers,
- Provide interim protection for existing heating customers,
- Ensure that programs are available to facilitate switching from electricity to natural gas as customers come to recognize that gas heating and water heating are preferable to electric use.
- Expand gas service areas where feasible.
- Provide alternatives for customers in areas without gas service, including grandfathered rates, enhanced programs for super-insulated and passive homes, geothermal heat pumps, and renewable biomass options.

In addition, the attractiveness of uneconomic electric heat for commercial customers has probably been increased by inclusion of high demand charges in the commercial rate designs, resulting in lower electric energy charges. This rate design reduces the price of using electricity in hours other than the customer's monthly peak and relying on gas primarily to shave the customer's load in the hours that set the billing demand. Since any one customer's electric load may be relatively low in many hours with high system loads, high demand charges subsidize electric use at high-cost times. Reducing demand charges and increasing energy charges (especially in the form of time-of-use rates) would better reflect MH's actual cost patterns and reduce wasteful electricity usage.

2.4.3 DSM

All of the market problems that Hydro identified as contributing to sub-optimal customer choices can be substantially overcome by utility programs that provide better information, rely on trustworthy vendors with appropriate incentives, pay an adequate share of capital cost and offer low-cost on-bill transferable financing to future residents.

Unfortunately, the 2013–2016 Power Smart Plan (Appendix E) does not discuss any particular effort to discourage uneconomic fuel-switching to electricity, or to encourage economic fuel-switching from electricity to gas. All the programs dealing with whole buildings and heating systems, residential and commercial, should include those provisions.

For example, the Power Smart Plan describes the Residential Earth Power Loan (REPL) program as follows:

> While more expensive to install, geothermal heat pump systems offer significant electricity savings, reducing customers' monthly utility bills. The convenience and flexibility of the on-bill REPL reduces the financial barrier that exists when installing a geothermal heat pump system.…Solar hot water systems were added as an eligible technology in 2010. Appendix E at 5)

The description of "more expensive to install, but offering significant electricity savings, reducing customers' monthly utility bills" applies as well to gas heat as to geothermal heat pumps. The Plan projects only about 90 installations annually under this program, compared to the thousands of electric space- and water-heating systems installed in areas with gas. Modifying the REPL to include gas furnaces and water heaters would be relatively simple and straightforward, although the program would need to be renamed.

In principle, the Power Smart Residential Loan Program could be used to promote gas heating, but MH does not appear to exploit this potential, either currently or in its plans. Electric space and water heating equipment is eligible for the Power Smart Residential Loan Program so long as they meet Canadian Standards Association requirements (GAC/MH I-084). The program does not particularly encourage switching to gas or discourage switching to electricity. MH does not even collect data on whether the loans are being used to switch gas uses to electricity: "Information regarding the water heating equipment being removed from the home is not collected as part of the loan application process" (GAC/MH I-089). Worse still, the program provides loans for uneconomic projects, including conversions:

> The objective of the program is to assist customers with implementing energy efficient opportunities by offering a convenient financing option. Eligibility to use the Power Smart Residential Loan is not restricted to only economic opportunities and the eligible opportunities are not subject to a cost-effective analysis. (GAC/MH I-085a).

Even the PAYS program requires that "the monthly payment for the funds borrowed from Manitoba Hydro must be less than the estimated average monthly utility bill savings" (GAC/MH I-091). Unfortunately, the PAYS program is also available for new construction (GAC/MH I-090), and the description of the cost-effectiveness test does not indicate that gas is assumed to be the default energy source in gas-available areas (GAC/MH I-092).

The most effective program for encouraging fuel-switching from electricity to gas might include technical support independent of the installation contractor (since customers may not trust the contractor's motives), inspection and approval of installations, incentives to customers, and PAYS financing facilitated by the technical review.

2.4.4 Hydro's terms and conditions

To the extent possible, developers of electrically heated homes should pay connection fees that reflect the costs imposed by the installation of electric heat on homebuyers and the province. Higher connection fees would discourage developers from selecting electric heat.

> Manitoba Hydro believes that its customers value the ability to have choice when it comes to selecting their heating source and would therefore be unlikely to place restrictions on individual extensions. However, Manitoba Hydro is currently examining changes to electric service extension policies to establish appropriate price signals to encourage natural gas heating systems in natural gas available areas. (GAC/MH I-082)

Hydro has known for many years about the problem of developers selecting energy sources that are uneconomic for its customers, so the fact that MH is still examining these changes is not promising.

Since MH has identified market barriers due to the reluctance of developers to "coordinate additional work crews associated with natural gas" and to investing any more than necessary in the building cost, an effective extension policy would raise the initial cost of electric heat and hot water to parity with the initial cost of gas heat and hot water. That approach would probably result in most developers opting for the electric lower extension costs associated with gas usage. If the policy collects excess funds (above the total system cost of the extension and the unnecessary electric use) for extensions to developments that persist in pursuing resistance heating, the difference can be used to fund additional efficiency for the affected customers, to fund other efficiency and renewable projects to offset the extra energy usage, or refunded to the affected customers over time.

2.4.5 Centra's terms and conditions

As a mirror image of the high line-extension charges for electricity service, lower charges to developers for gas connections would also tend to encourage the selection of gas over electricity. Hydro is in a very favourable position, compared to most electric utilities, in that it owns the gas distributor. Payments from Power Smart to Centra to provide gas connections and overcome the first-cost concern would be consistent with incentives to other trade allies.

3 Feasible DSM Targets (Resource Insight Inc.)

According to the annual surveys by the ACEEE through 2011, several jurisdictions have achieved annual DSM program savings in excess of 1.3% of retail sales, including Vermont, Connecticut, Massachusetts, Rhode Island, California, Hawaii, and Nevada. The first four of those states are projecting savings of 2% to 2.5% annually in the near future, and the Northwest Power and Conservation Council is planning to ramp up from 1.3% savings in 2013 to 1.6% by 2017. Many of those jurisdictions have been leaders in energy-efficiency programing for decades, and yet they still that they are able to achieve large usage reductions.

Nova Scotia's annual savings since 2012 have been also been 1.4%–1.5% of sales. None of these jurisdictions has Manitoba's combination of significant saturation of electric space and water heating with high availability of natural gas as an alternative.

These savings do not include the effects of non-program efforts, such as codes, standards, and regulations, which MH reports as providing 46% of the energy savings from active programs from 2009/10 to 2012/13.

Considering the combination of fuel-switching for electric heat and hot water and the potential for non-program savings, MH should be able to reach 2% annual savings for several years. A conservative estimate of long-term DSM savings would be on the order of 1.5% annually.

Hydro is currently projecting savings of about 0.4% savings in 2014/15 (Appendix 4.2 at 122), so ramping up to 1.5% annual savings will take a while. A reasonable ramp-up schedule would be as shown in Table 3-1.

Table 3-1: Reasonable DSM Energy Targets

	Annual Savings as % Energy	Cumulative GWh Savings
2014/15	0.6%	269
2015/16	0.9%	487
2016/17	1.1%	761
2017/18	1.3%	1,089
2018/19	1.5%	1,472
Annually post 2018/19	1.5%	+~385/yr

While the ratio of peak savings to energy savings from energy-efficiency programs can be estimated in several ways, producing ratios as high as 0.24 MW/GWh, the subsequent analysis in this report assumes a more conservative 0.21 MW/GWh, equivalent to about a 54% load factor. By 2018/19, applying this ratio to the energy reductions in Table 3-1 produces annual peak savings of about 81 MW.

3.1 Planning Implications of Aggressive DSM

The tables in the Appendix: Adjusted Supply-Demand Balance Tables summarize the effect of aggressive DSM implementation on the load and capacity requirements for MH's 2013 load forecast and the "No New Resources" case (Appendix 4.2 at 120–123), which includes domestic load and a minimal level of exports (the "Minimal Export" case). Hydro's version of these tables show Exportable Surplus disappearing, and Manitoba falling into deficit for capacity in 2026/27 and for energy in 2022/23. That need is the immediate driver of Keeyask's schedule.

The corresponding version with aggressive DSM shows exportable surpluses of both capacity and energy in all years. Those results indicate that no new resources—not Keeyask, Conawapa, wind or gas—will be required to meet domestic Manitoba loads through the forecast period.[8]

Furthermore, the surpluses are large enough that MH could make all of the contracted and proposed sales in the "K19/C26/750MW (WPS Sale & Inv)" case, with the exception of small shortages of capacity (less than 70 MW) in five years in the early 2030s and of energy (less than 115 GWh) for three years starting 2022/23. The deficiencies are much smaller than Keeyask's 630 MW deendable capacity and 3,000 GWh dependable annual energy output. Those results are summarized in Table 3-2.

[8] In the event that Hydro's implementation of DSM does not ramp up to quite the levels discussed above, wind plants can be built quickly to supply additional energy.

Table 3-2: Surplus with Contracted and Proposed Sales

	Capacity Surplus (MW)		Energy Surplus (GWh)	
	Minimal Exports	*Contracted and Planned*	*Minimal Exports*	*Contracted and Planned*
2014/15	340	221	868	420
2015/16	566	447	1,806	1,269
2016/17	563	444	1,902	1,364
2017/18	684	565	2,125	1,587
2018/19	687	568	2,103	1,565
2019/20	692	573	2,073	1,535
2020/21	750	356	2,267	693
2021/22	754	232	2,276	7
2022/23	754	232	2,244	-58
2023/24	752	230	2,220	-82
2024/25	752	230	2,189	-113
2025/26	724	339	3,485	1,703
2026/27	722	117	3,468	897
2027/28	723	118	3,435	698
2028/29	719	114	3,391	654
2029/30	716	111	3,352	615
2030/31	540	-65	3,324	587
2031/32	539	-66	3,328	591
2032/33	538	-67	3,307	570
2033/34	537	-68	3,286	549
2034/35	536	-69	3,272	535
2035/36	535	205	3,247	1,546
2036/37	534	534	3,224	2,975

Additional generation resources may be justified to enable additional exports, including the 500 MW sale currently under discussion with Saskatchewan for some time after 2020. Those resources might include Keeyask and/or Conawapa, but may well include wind resources, depending on the relative costs, risk and operational characteristics. In addition to the wind resources in Manitoba, wind projects in the US Upper Midwest may be combined with MH's hydro resources (both existing and new) to provide additional firm renewable power to Saskatchewan, the US, and/or Ontario. In any case, the new resources should only be added if the export revenues would more than cover the capital and operating costs of the required resources. If MH can identify specific additional contracts that would justify building some mix of new hydro and wind resources, it could file an updated NFAT with more realistic consideration of the cost and risk mitigation of wind development.

Hydro's case in this proceeding does not include a realistic treatment of either DSM or wind options and therefore cannot be relied on as a basis for commitment to the projects it has proposed. It is likely that Hydro could demonstrate that the 750 MW transmission line would be justified by revenues from increased sales under existing and proposed export contracts, especially if those exports require little or new investment in generation resources. Justifying new major generation facilities would require a more substantial analysis, once the new contracts are in hand.

4 Role of Wind Energy (Power Advisory LLC)

4.1 Introduction

4.1.1 Background

Manitoba Hydro has approximately 5,700 MW of installed capacity, the vast majority of which is hydroelectric, with just two fossil generating stations providing 458 MW, which are used for backup in low water years. Manitoba Hydro's electricity system also includes two major wind farms, with a combined nameplate capacity of approximately 260 MW. The Preferred Plan does not include any additional wind capacity, although Manitoba Hydro's NFAT application states that "Additional wind generation and non-utility generation such as biomass will be developed when and if they become economic."[9]

4.1.2 Power Advisory's Area of Interest

Power Advisory LLC was retained by the Green Action Centre to provide input to the NFAT process. PUB Order 127/13 set out Power Advisory's mandate as "to review and analyze wind energy being integrated as an alternative energy source for Manitoba Hydro. While the issue raised by GAC requires review and analysis, the Board expects one of the Independent Expert Consultants (La Capra Associates together with EnerNex) to also review and analyze wind energy alternatives, such that duplication by GAC's consultants is not required. Rather, through consultation, GAC's intervention should supplement the work being performed by the Independent Expert Consultants appointed by the Board within the revised budget approved, without requiring duplication of analysis and modeling."[10]

Given this charge, Power Advisory has focused on two main issues:

- The accuracy of assumptions used by Manitoba Hydro regarding the cost and value of wind generation as an alternative energy source
- The completeness of the alternative Plans analyzed by Manitoba Hydro, and in particular whether these Plans have adequately considered wind generation.

4.1.3 Manitoba Hydro's Analysis of Wind Generation

Manitoba Hydro's NFAT application considered several types of electricity supply, including hydro, wind (on-shore and off-shore), solar, biomass, and gas (SCGTs and CCGTs). It first screened generation technologies based on their Long-term Cost of Energy (LCOE), and then combined them in into 15 development plans which were compared on the basis of their Net Present Value.

[9] Manitoba Hydro, *Needs For and Alternatives To* (hereinafter abbreviated "MH NFAT"), Overview, p. 3.
[10] Manitoba Public Utilities Board, *Order No. 127/13: NFAT Procedural Order on Matters Arising From the September 4, 2013 Pre Hearing Conference*, October 21, 2013, p. 7.

Manitoba Hydro estimated that the LCOE of wind is $84/MWh in 2014 dollars, including transmission[11], which is significantly higher than Manitoba Hydro's estimate of the LCOE of either Keeyask ($60/MWh) or Conawapa ($67/MWh).[12] Manitoba Hydro included new wind generation in two of its 15 development plans:

- "Wind/Gas", with new wind capacity coming into service in 2022/23, supported by new gas capacity beginning in 2025/26, but no new hydro capacity.
- "Wind/C26", with wind capacity in 2022/23 and Conawapa coming into service in 2026/27, but without Keeyask.

These two development plans were found to be much worse than the Preferred Plan by approximately $2 billion and $1 billion respectively, in NPV terms.[13] Manitoba Hydro did not analyze any development plants that included both new wind generation and new intertie capacity. Manitoba Hydro concluded that "While wind farms have successfully been established in Manitoba and will continue to be considered, wind generation as a major generation supply in Manitoba was determined not to be economic at this time."[14]

4.2 Wind Cost Assumptions

4.2.1 Introduction

Power Advisory's first step was to assess the Manitoba Hydro's assumptions regarding the cost of wind. Manitoba Hydro, in its response to Information Request LCA/MH I-308, provided a spreadsheet ("lca_308_attachment_1.xlsx") containing the assumptions and calculations used in deriving the LCOEs of all technologies considered, including wind. Eight slightly different configurations of on-shore wind projects are included in the spreadsheet. In this section of our analysis, we will focus on the calculations and assumptions for a generic 65-MW wind project with Stage I capital costs and Reference Case project costs, as this is what Manitoba Hydro used in its screening process.[15] Each assumption is reviewed in turn, followed by a recalculated LCOE based on recommended adjustments to the assumptions.

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[11] Manitoba Hydro response to Information Request GAC/MH II-003a, posted January 10, 2014. Elsewhere in Manitoba Hydro's filings, a range of LCOE numbers, variously in 2012 or 2014 dollars, and without or without transmission costs included. As well, the wind LCOE numbers in the original application were found to be too high, due to an error in the capital cost used in the calculations.

[12] MH NFAT Chapter 7 – Screening of Manitoba Resource Options, p. 39. All amounts are in 2014 dollars. The LCOE of wind is shown as $86/MWh, but this was later corrected to $84/MWh.

[13] MH NFAT Appendix 9.3 – Economic Evaluation Documentation, Table 2.71, as corrected in Manitoba Hydro's response to PUB/MH I-174.

[14] MH NFAT, Chapter 14 – Conclusions, pp. 3-4.

[15] MH NFAT, Chapter 7 – Screening of Manitoba Resource Options, p. 33: "a generic 65 MW wind farm was created for use in future assessments and evaluations". While this page does not specify Stage 1 transmission costs, this sheet of lca_308_attachment_1.xlsx gives a result of $84, which corresponds to the corrected LCOE given in GAC/MH II-003a. The LCOE shown for a 100-MW project (reference case capital costs, Stage I transmission costs), is only 0.3% higher than that shown for the 65-MW project. Using Stage II transmission costs increases the LCOE by 5%.

4.2.2 Capital Costs

4.2.2.1 Base 2012 Capital Costs

Manitoba Hydro assumed a reference case capital cost of $2,100/kW for the project itself, plus $50/kW for transmission station costs and $150/kW for transmission line costs, for a total of $2,300/kW. This assumption has been addressed by two of the PUB's Independent Expert Consultants (IECs). Knight Piesold recommends using a base cost of $1,800/kW (excluding transmission), noting that:

> Furthermore, there is some optimism among wind energy experts that further technological advances and cost reductions are possible (REN21 , 2013b; IPCC, 2012). Considering this likelihood, and the fact that the data is based on projects installed in 2012 (that is, data that is already out of date), a base cost of $1,800/kW should be considered conservative.[16]

La Capra Associates also concludes that Manitoba Hydro's capital cost assumption is too high, noting that:

> The US Department of Energy report also looked at regional difference for project costs in the United States. It found that the capacity weighted average installed costs for projects in the interior region, which includes the central portion of the country from Montana, Minnesota, and North Dakota south to Texas and New Mexico, were about $1,750/kW in 2012 including transmission interconnection costs.[17]

Both IECs put considerable weight on the above-mentioned US Department of Energy report, and in particular the average project cost of $1,760/kW for 42 projects totalling 3,827 MW installed in the "Interior" region (which borders Manitoba) in 2012.[18] Knight Piesold appears to have rounded this up to $1,800 to come up with their recommendation[19], without taking into account that the Department of Energy number includes transmission interconnection costs.[20]

Power Advisory recommends using the Department of Energy's average of $1,760/kW for the Interior region as a reasonable estimate of wind capital costs in 2012. This includes both project and interconnection costs; we recommend splitting the total into these two components, as the costs may not change over time at the same rate. Manitoba Hydro assumes a transmission station cost of $50/kW. As we have no other basis for estimating this, we recommend assuming $1,710/kW as the project cost and $50/kW as the transmission station cost.

The bulk of project costs will be for internationally-traded components such as the turbine, and will therefore be subject to fluctuations in the exchange rate. The Canadian and U.S dollars were at

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[16] Knight Piesold Independent Consulting Report (Redacted), January 17, 2014, p. 49

[17] La Capra Associates, *Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations*, Technical Appendix 2 – Generation Alternatives, p. 13.

[18] U.S. Department of Energy, *2012 Wind Technologies Market Report*, Figure 23, p. 36.

[19] Knight Piesold, p. 49: "On this basis, the expected "base case" capital costs rounded to the nearest $1 00/kW would be approximately $1 ,800/kW".

[20] U.S. Department of Energy, p. 35: "In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses."

approximately at parity in 2012 so no adjustment needs to be made to 2012 prices. For prices in future years, Manitoba Hydro's exchange rate assumption (C$1.04 per US$1.00) should be used.

In addition to direct project and transmission station costs, Manitoba Hydro's LCOE calculation includes transmission line costs of $150/kW. Power Advisory is not in a position to comment on this assumption.

4.2.2.2 Trends in Wind Capital Costs

Manitoba Hydro assumed that wind capital costs would neither increase nor decrease in real terms:

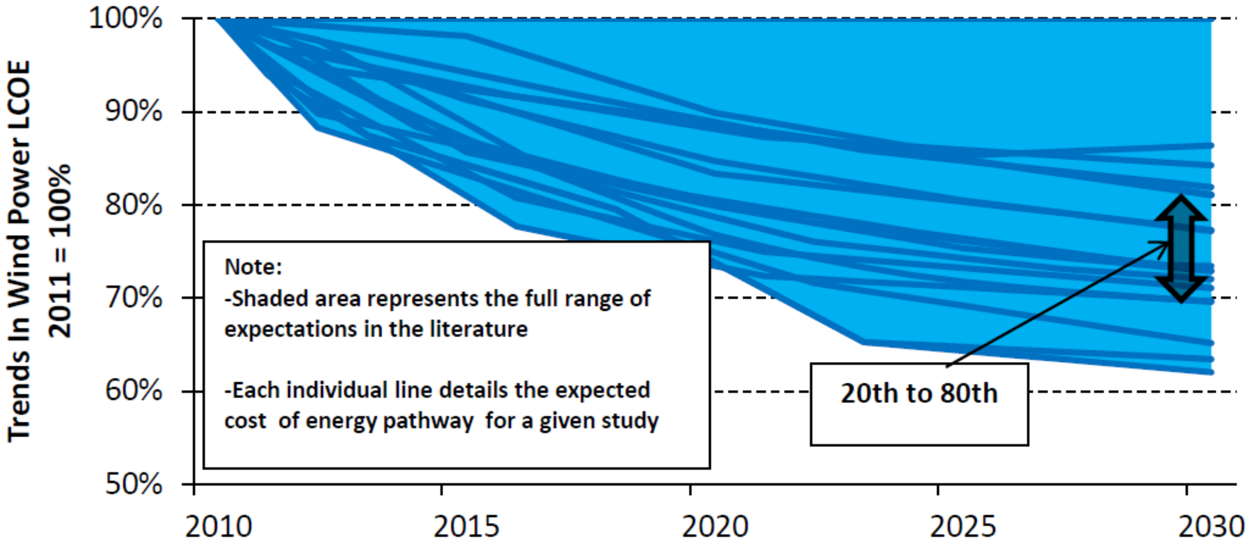
> In the NFAT Business Case, reference capital costs were based on current costs for wind generation with no escalation going forward. Energy output for wind generation resources was based on a 40% capacity factor.
>
> The 40% capacity factor assumed in the analysis is consistent with recent experience for wind generation resources in Manitoba having 80 metre hub heights. Forecasted increases in energy output from wind turbines are to a large degree dependent on having larger turbines and/or having higher hub heights (higher towers) accessing higher wind speeds. However, there is uncertainty as to whether such improvements will materialize. Should such benefits materialize any resulting increase in energy output would have to offset higher costs associated with larger turbines and tower construction.
>
> Key factors driving Manitoba Hydro's assumption to use current wind generation costs for the reference capital cost and a 40% capacity factor include uncertainty in infrastructure costs related to higher towers, technical challenges with erecting higher towers, and uncertainty in commodity prices.[21]

Manitoba Hydro made this assumption despite its own statement that "Advancements in the design and construction of wind turbine generators, such as individual wind turbines increasing from 1 to 3 MW in size, have the potential for reducing the cost of utility scale wind and may improve its economics in the near future."[22]

Both Knight Piesold and La Capra Associates note that wind capital costs are expected to decrease. La Capra Associates quotes a U.S. National Renewable Energy Laboratory (NREL) report which summarized 18 projections of wind LCOE from 13 sources, as shown in Figure 1. NREL notes that "The normalized data suggest an absolute range of roughly a 0%–40% reduction in LCOE through 2030 … by focusing on the results that fall between the 20th and 80th percentiles of scenarios, the range is narrowed to roughly a 20%–30% reduction in LCOE."

[21] Manitoba Hydro, response to GAC/MH I-004a.
[22] MH NFAT, Appendix 7.2 – Range of Resource Options, p. 338.

Figure 1: Estimated Range of Wind LCOE Projections Across 18 Scenarios[23]



Manitoba Hydro is correct that there is uncertainty in wind costs; one of the 18 scenarios included in NREL's study projected no further cost reductions. However, reference case assumptions should be based on the most likely scenario – which, based on NREL's report, is a 20-30% decrease in LCOE – rather than on a worst case scenario.

NREL's graph shows projections of LCOE, not capital costs per se, with the declines due to a combination of decreasing capital costs and increasing capacity factors. NREL's report does not provide enough information to distinguish between the two factors. However, they can be treated as more-or-less equivalent: a decline in capital costs has much the same effect on LCOE as an increase in capacity factor, and is much easier to model using Manitoba Hydro's LCOE spreadsheet.

La Capra Associates, in their sensitivity analysis, assumed a 1%/year decline in capital costs through 2032.[24] Power Advisory recommends a more moderate decrease, not as a sensitivity case but to be incorporated in the base case. Based on the U.S. Department of Energy study, we recommend that wind capital costs be assumed to decline by 25% (i.e., the middle of the 20-30% range) between 2010 and 2030. Some of this decrease has already happened: about 13%, according to a U.S. Energy Information Administration report.[25] The remaining decrease, to a total of 25%, could be approximated by an annual decline of 0.8%/year (compounding). Further decreases beyond 2030 are possible, but we do not have a basis on which to estimate them.

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[23] National Renewable Energy Laboratory, *The Past and Future Cost of Wind*, IEA Task 26, May 2012, Figure 11, p. 26. The same figure is shown in MH NFAT Appendix 3.1, on p. 72 of the Brattle Group report on "Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO".

[24] La Capra Associates, *Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations*, Technical Appendix 3A –Alternative Resource Plans, p. 26.

[25] US EIA, *2012 Wind Technologies Market Report*, p. 34: "In 2012, the capacity-weighted average installed project cost stood at roughly $1,940/kW, down almost $200/kW from the reported average cost in 2011 and down almost $300/kW from the apparent peak in average reported costs in 2009 and 2010." As noted above, project costs for the U.S. region bordering Manitoba are significantly lower than the national average.

The two development plans included in Manitoba Hydro's NFAT that incorporate wind both assume in-service dates of 2022/23. Assuming a base capital cost of $1710/kW in 2012 dollars, and applying a downward trend of 0.8%/year, the project capital cost in 2022 would be approximately $1,580/kW in 2012 dollars, or approximately $1,630 in 2014 dollars. Transmission station and line costs need to be added to this. While it is possible that transmission costs will also decline due to technological advances, we have no basis for making such an assumption.

4.2.2.3 Construction Period

Manitoba Hydro's LCOE calculations, as shown in the spreadsheet lca_308_attachment_1.xlsx, assumes a three-year construction period, with approximately 3% of capital costs incurred in the first year, 95% in the second, and 2% in the third. Power Advisory is not aware of any evidence provided by Manitoba Hydro to support this assumption, and because the spreadsheet was released after the deadline for Information Requests, we were no able to ask for supporting documentation.

Based on our experience in the wind development industry, we consider this assumption of a one-year gap between the bulk of capital cost expenditures and the in-service date to be significantly pessimistic. The assumption of 3% of capital costs three years before the in-service date is not unreasonable, but we would recommend splitting the remaining capital costs evenly between the next two years, resulting in a three-year capital expenditure schedule of 3%/48.5%/48.5%. Even this may be pessimistic, as one-year construction schedules for similar scale projects are common. Black and Veatch assumed a 12-month construction period for on-shore wind projects in their work for NREL. [26]

4.2.2.4 Project Life

Manitoba Hydro has assumed that new wind projects would have a useful life of 20 years, even though, as noted by La Capra Associates, "MH has a 25-year PPA with the St. Leon wind project and a 27-year PPA with the St. Joseph wind project." Wind Power Purchase Agreements often have a term of 20 years.

Manitoba Hydro justifies this assumption as follows:

> Asset or design life of 20 years is currently accepted within the industry for evaluation of wind projects. This is based in part on historic experience with existing wind installations recognizing there is uncertainty in the expected life of the various components of larger multi-megawatt wind turbines which are currently being installed.[27]

It explains the term of the St. Joseph contract as follows:

> The agreement for the St. Joseph Wind Project has a term of 27 years which is an extension of 7 years beyond what is considered normal in the industry. Although the agreement details are confidential, Manitoba Hydro and the wind developer were able to agree to contract language that addressed the specific obligations, costs and risks associated with the extended term.

[26] Black and Veatch, *Cost and Performance Data for Power Generations Technologies*, Prepared for the National Renewabe Energy Laboratory, February 2012, p. 46.
[27] Manitoba Hydro, Response to GAC/MH I-010a.

In Power Advisory's experience, 20 years is a common term for wind power contracts, as developers are very confident that the turbines will operate well at least that long. However, again in our experience, developers typically assume that wind projects will continue to operate for 25 years – i.e., 5 years longer than the term of their contract. Operations and maintenance (O&M) cost estimates typically reflect funding for replacement of critical components such as the gearbox.[28]

Since Manitoba Hydro's analysis is based on that assumption that it would own the wind projects (rather than entering into a Power Purchase Agreement with a private developer), it is appropriate to base the LCOE calculations on the expected equipment life, not the length of a typical contract. Power Advisory recommends assuming a life of 25 years for the turbines and related equipment, after which they will be replaced. This is consistent with the terms of the St. Joseph and St. Leon project PPAs.

As noted in Appendix 9.3 of the MH NFAT (p. 2), the expected economic life of transmission equipment is 35 years for stations and 50 years for lines. We recommend assuming replacement these types of equipment on those schedules.

Because Manitoba Hydro assumed that wind projects had only a 20-year life, followed by full replacement at original cost (including all transmission costs), its LCOE calculations extended only over the construction period plus 20 years. With Power Advisory's recommended changes – replacement of turbines, transmission stations and transmission lines at different times based on their different economic lives, and replacement of turbines at 80% of the then-current cost of a new wind project – the LCOE analysis needs to be extended out to the same term as is used for Keeyask and Conawapa: to construction plus 68 years.

4.2.3 Wind Operating Parameters

4.2.3.1 Capacity Factor

Manitoba Hydro has assumed a capacity factor of 40%, "consistent with recent experience for wind generation resources in Manitoba having 80 metre hub heights."[29] La Capra Associates has questioned this assumption, noting recent projects in the region with an average capacity factor of 42%[30], and assuming a 43% capacity factor in its sensitivity analysis.[31] Manitoba Hydro's existing wind projects achieved commercial operation in 2007 and 2011. Since then, a number of wind turbine manufacturers have offered new longer blades for existing wind turbine generator models to increase project output in moderate wind regimes. For example, Siemens Wind Power offers a SW2.3 with 108 meter diameter blade while the St. Joseph wind farm employs a SW 2.3 with a 101 meter diameter blade. A 108 meter

[28] See for example U.S. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, p. 21-3. The EIA's estimated O&M cost of $39.55/kW, which matches Manitoba Hydro's assumption, includes "periodic gearbox, WTG, electric generator, and associated electric conversion (e.g., GSU) technology repairs and replacement."

[29] Manitoba Hydro, response to GAC/MH I-004a. Manitoba Hydro's response to

[30] La Capra Associates, *Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations*, Technical Appendix 2 – Generation Alternatives, p. 10.

[31] La Capra Associates, *Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations*, Technical Appendix 3A –Alternative Resource Plans, p. 26.

blade offers a swept area which is 14% greater than a 101 meter blade and this typically translates into higher capacity factors.

As noted above, the U.S. Department of Energy has documented numerous studies that project significant declines in the LCOE of wind, primarily through a combination of lower capital costs and higher capacity factors (both associated with larger towers). Power Advisory recommends above that these declines should be captured in an assumption that capital costs will decline. To assume both declining capital costs and increasing capacity factors runs the risk of double-counting. Power Advisory has therefore retained Manitoba Hydro's assumption of a 40% capacity factor, while noting that a higher capacity factor may be appropriate for new projects with larger towers.

4.2.3.2 Fixed Operating and Maintenance Costs

Manitoba Hydro states that it assumes a Fixed O&M cost of $39.55/kW-year in 2012 dollars.[32] This is consistent with Power Advisory's experience. However, the actual cost assumption used in the LCOE calculation spreadsheet (lca_308_attachment_1.xlsx) is $46/kW-year in 2012 dollars (e.g., $2.99 million/year for a 65-MW project, and $4.60 million/year for a 100-MW project). No explanation for this discrepancy is provided.

Power Advisory recommends using the stated assumption of $39.55/kW-year in 2012 dollars.

4.2.3.3 Wind Integration Costs

Manitoba Hydro states its wind integration assumptions as follows:

- 500 MW of wind generation: $4.22/ MWh (2005 dollars)
- 1000 MW of wind generation: $4.99/ MWh (2005 dollars)

> The unit wind integration costs are expressed on a marginal basis for each 100 MW increment of wind, and scaled to the current long-term export price forecast using the ratio of the current long-term price forecast divided by the 2005 price forecast.[33]

These amounts were based on a 2005 study by Synexus Global.[34]

In response to Information Request GAC/MH I-013, Manitoba Hydro stated:

> Specific adjustments to the 2005 wind integration cost estimates have not been made for the referenced refinements such as improved wind forecasting, wind ramp-up predictability, and sub-hourly scheduling. Manitoba Hydro's initial experience with wind integration was that the 2005 wind integration studies may have under estimated the required generation hold back/reserves required for wind integration and hence wind integration costs may have been slightly higher than the 2005 study result. Manitoba Hydro has adopted forecasting and

[32] MH NFAT, Appendix 7.2 – Range of Resource Options, p. 327 and p. 334

[33] MH NFAT, Appendix 9.3 – Economic Evaluation, p. 26.

[34] Cited as "Synexus Global, A Study to Evaluate the Short-Term Operational Impacts of Wind Integration into the Manitoba Hydro System, December 2005."

scheduling improvements as they became available, and today Manitoba Hydro's wind integration experience is generally consistent with the 2005 study results.

In response to Information Request GAC/MH I-014, Manitoba Hydro declined to provide copy of the 2005 report by Synexus Global, on the grounds that it "would require the disclosure of Commercially Sensitive Information". Manitoba Hydro did provide a copy of another study on wind integration, by EPRI Solutions, also from 2005, but wind integration assumptions used in the NFAT analysis were not based on this report.

It is far from clear, based on Manitoba Hydro's responses quoted above, exactly what wind integration cost it is using. Linear extrapolation of the Synexus Global numbers ($4.22/MWh with 500 MW of wind, $4.99/MWh with 1000 MW) imply that each additional MWh of wind generation adds $5.76/MWh of wind integration costs. This is in 2005 dollars, and should be adjusted "using the ratio of the current long-term price forecast divided by the 2005 price forecast" (see above). This presumably refers to U.S electricity prices. Manitoba Hydro's price forecasts are considered Confidential Information. However, since MISO wholesale market prices are currently significantly lower than they were in 2005, it would be unreasonable to increase this estimate of wind integration costs, and it would not be unreasonable to decrease it.

The actual wind integration cost that Manitoba Hydro used in calculating the LCOE of wind, taken from the spreadsheet lca_308_attachment_1.xlsx, is $8.45/MWh in 2012 dollars ($1.93 million/year vs. 228 GWh/year for a 65-MW project; $2.96 million/year vs. 351 GWh/year for a 100-MW project). It is difficult to see how this is consistent with a cost of $4.22, $4.99 or $5.76/MWh in 2005 dollars, given the declines in MISO electricity prices since then.

Manitoba Hydro's wind integration cost is a black box, with the actual cost used inconsistent with the small amount of information provided. Power Advisory recommends using a wind integration cost of $5.76/MWh in 2012 dollar, recognizing that this may well be an overestimate.

4.2.4 Revised LCOE Calculation

The table below shows the impact of each of the assumption changes recommended by Power Advisory, and the resulting LCOE. The assumption changes with the biggest impact are:

- Updating the 2012 capital cost, with further declines until the project is built
- Using a 25-year equipment life for the turbines
- Reducing the wind integration cost

Assuming redevelopment at less than the original cost does not have a significant impact.

Table 4-1: Impact of Assumption Changes on LCOE

Assumption Change	LCOE with Cumulative Changes (2014 $/MWh)	Impact of Single Change (2014 $/MWh)
Original Manitoba Hydro LCOE Estimate	**$84.07**	
+ 2012 Capital Cost: $1,710/kW + transmission	$73.73	-$10.34
+ Capital Cost: Declining to 2022	$70.19	-$3.54
+ Revised Construction Schedule	$69.20	-$0.99
+ 25-Year Project Live (longer for transmission)	$63.55	-$5.65
+ Fixed O&M Cost: $39.55/kW-year	$61.64	-$1.91
+ Fixed Wind Integration Cost: $5.76/MWh	**$58.85**	-$2.79

For comparison, the LCOEs (at load) of Keeyask and Conawapa, in 2014 dollars, are $60.21 and $66.26 per MWh. Wind is thus less expensive than either Keeyask or Conawapa on an LCOE basis.

4.3 Role of Wind in Development Plans

4.3.1 Development Plans Including Wind

As discussed in Section 1.3 above, Manitoba Hydro included new wind generation in two of its 15 development plans:

- “Wind/Gas”, with new wind capacity coming into service in 2022/23, supported by new gas capacity beginning in 2025/26, but no new hydro capacity.
- “Wind/C26”, with wind capacity in 2022/23 and Conawapa coming into service in 2026/27, but without Keeyask.

These two development plans were found to be much worse than the Preferred Plan by approximately $2 billion and $1 billion respectively, in NPV terms.[35]

La Capra Associates, in its report, recalculated the results of these two cases with the following wind assumptions changed[36]:

- Capital cost: $1,750/kW
- Capacity factor: 43%
- Lifetime: 25 years
- Cost decline over time: 1%/year through 2032

[35] MH NFAT Appendix 9.3 – Economic Evaluation Documentation, Table 2.71, as corrected in Manitoba Hydro’s response to PUB/MH I-174.

[36] La Capra Associates, *Needs For and Alternatives To (NFAT) Review of Manitoba Hydro’s Proposal for the Keeyask and Conawapa Generating Stations*, Technical Appendix 3A –Alternative Resource Plans, p. 26.

While these changes do not make either case less expensive than the Preferred Plan over the entire study period (through 2090), both plans would be less expensive than the Preferred Plan of the calculation was done over a somewhat shorter period: "Changing to LCA's wind assumptions moves the crossover point [the point at which the Preferred Plan has a better Net Present Value] out 11 years to 2057 for the Wind Gas Plan and 10 years to 2052 for the Wind Conawapa Plan."[37] In other words, the advantage of the Preferred Plan over the two development plans that include wind rests on the accuracy of forecasts, in particular export price forecasts, looking more than 40 years into the future.

We would note that La Capra Associates' analysis does not go far enough in two respects:

- In our view, even La Capra Associates' assumptions overestimate the cost of wind, in particular by ignoring Manitoba Hydro's overestimation of fixed O&M and wind integration costs. We have recalculated the LCOE of wind using La Capra Associates' assumptions for a wind project going into service in 2022, and found it to be $66/MWh, compared to our estimate of $59/MWh (both in 2014 dollars).

While modelling was beyond Power Advisory's mandate, it is possible that, if both of these factors were taken into consideration, one or both of the development plans with wind could be more cost-effective than the Preferred Plan, even over the period out to 2090.

4.3.2 Combining Wind with Interties

Manitoba Hydro did not analyze any development plans that included both new wind generation and new intertie capacity. Manitoba Hydro concluded that "While wind farms have successfully been established in Manitoba and will continue to be considered, wind generation as a major generation supply in Manitoba was determined not to be economic at this time."[38] Power Advisory's analysis, concluding that the LCOE of wind is lower than that of either Keeyask or Conawapa, calls Manitoba Hydro's conclusion into question.

In Power Advisory's view, development plans that incorporate new wind generation, a new intertie with the U.S., and increased exports would be well worth investigating. It is possible that wind could be used to replace or at least postpone either Keeyask or Conawapa, which could result in significant cost savings. A crucial aspect of any such development plan is that the additional wind generation should be treated as a system resource, contributing along with other system resources to meeting combined domestic and export demand, rather than necessarily being exported. On the whole, over a year or more, additional wind generation would translate into additional potential for export, but the additional exports could be made when they most benefit Manitoba, not necessarily when the wind is blowing. How much wind could be developed on this basis, and how much value it would add, depends on the hour-by-hour relationship between domestic demand, wind generation and the demand for exports, as well as the storage capabilities of Manitoba's hydro plants.

[37] Op. cit., p. 28.
[38] MH NFAT, Chapter 14 – Conclusions, pp. 3-4

Manitoba Hydro was asked about a potential relationship between wind generation and hydro storage in information request PUB/MH I-026a: "Please provide an updated history of MH's purchased wind energy (MW/GWh/year) and discuss the potential for more Manitoba wind energy capacity while employing Lake Winnipeg and other reservoir storage to optimize the wind energy value." Manitoba Hydro responded as follows:

> Under today's market and regulatory environment it is not viable to develop additional wind energy in Manitoba using existing reservoir storage and transmission line capacity to provide that firm power to US customers for the following reasons:
>
> a) Information provided from potential Manitoba wind developers indicates that the cost of new wind power projects far exceeds the current market energy price in the US market. Developers are unwilling to assume any future market price risk.
> b) US customers have access to relatively inexpensive wind energy because of US federal subsidies.
> c) Wind energy from Manitoba may technically qualify for meeting US Renewable Portfolio Standards (RPS) in some jurisdictions but Manitoba Hydro's US customers are not interested in purchasing wind energy from Manitoba to meet state RPS requirements.
> d) New wind generation development in Manitoba would not enable the construction of new transmission for Manitoba's benefit in the US. As indicated in the MISO Wind Synergy Study, only new hydro generation provides dispatchable capacity and storage services which are needed in the MISO market to accommodate US wind integration. New Manitoba wind generation for export would exacerbate the issues associated with developing US wind resources and would result in increased integration costs rather than lower costs. To the extent US utilities invest in new transmission for wind, it will be to support the development of local wind resources that qualify for RPS recognition.
>
> In summary, US customers and regulators have shown no interest in wind energy from Manitoba and are unwilling to enter into contracts for such energy. It would be uneconomic for Manitoba Hydro to develop additional wind energy in Manitoba for export purposes.

Several aspects of this reply are noteworthy:

- Wind exports are evaluated based on current export prices, whereas the NFAT considers future prices.
- US federal tax subsidies are not available for any wind projects completed after 2015.
- Wind developers are assumed to assume all price risk, whereas in the NFAT, Manitoba Hydro, and through it, the ratepayers of Manitoba, take on the price risk associated with hydro exports.
- Wind is assumed to be exported to the U.S. on a stand-alone basis, whereas the NFAT considers how total system exports could be increased.
- Manitoba Hydro's reasons for rejecting this possibility are based on (incorrect) market considerations, not on technical considerations.

A possible objection to any development plan that postpones Keeyask while retaining an intertie is that the interties under consideration are contingent on export contracts which in turn are contingent on development of new hydro capacity in Manitoba.[39] However, it is not clear why the recipients (Minnesota Power, Northern States Power, or Wisconsin Power) would require the development of new hydro facilities. The recipients have an obvious interest in a guarantee that the power would delivered as contracted. Manitoba Hydro has not explained why the purchasers would care whether the power would come specifically from Keeyask, or specifically from new hydro.

It is not clear whether the type of development plan proposed in this section (developing a new intertie, with wind used to postpone or replace Keeyask and/or Conawapa) would be

- Technically feasible (i.e., if wind generation served domestic load, could hydro exports be increased?)
- Politically and legally feasible (i.e., would the counterparties be open to delinking the contracts and interties from new hydro development?)
- Economically feasible (i.e., more cost-effective than the Preferred Plan).

Power Advisory recommends exploring these questions, rather than dismissing the possibility without investigation.

4.4 Additional Considerations

In addition to the considerations quantified through either the LCOE calculation or the NPV assessment of the alternative development plans, the following factors should be considered in comparing wind to alternative types of generation, particularly large hydro:

- Renewable Energy Credits: Manitoba Hydro asserts that wind in Manitoba would not be able to participate in REC markets. "Manitoba Hydro does not realize any Class I REC value for the sale output of the St. Leon and St.Joseph wind projects. The St. Leon and St. Joseph wind farm output does not qualify under U.S. state renewable portfolio standards as Class I RECs because the generation is external to the U.S.." (GAC/MH -018c) This response contradicts Manitoba Hydro's response to PUB/MH I-026a which acknowledges that these projects can participate in some state RPS. Power Advisory understands that to qualify under the renewable energy tracking program commonly employed the renewable energy attributes must be bundled with the energy. Given the significant export volumes sold by Manitoba Hydro to these markets there are likely to be many periods when wind is being generated in Manitoba at the same time that Manitoba Hydro is exporting to the US, thus satisfying these renewable energy tracking programs.

- Flexibility: Wind and gas projects can be developed quickly, in as little as 2 years from commitment of major capital to full output, compared to approximately 6-12 for major hydro

[39] MH NFAT, Chapter 6 – The Window of Opportunity, Table 6.4, p. 28 lists six contracts which are contingent on new hydro development, with four of them being specifically contingent on Keeyask.

projects such as Keeyask and Conawapa. Wind and gas projects can thus be held in reserve and completed only if warranted by demand, whereas large hydro projects can lead to over-supply. This could be particularly problematic if the over-supply was caused by a widespread economic downturn, as it would be likely be accompanied by depressed electricity market prices.

- Diversity. Annual wind generation varies from year to year, though less than annual hydro generation; Manitoba Hydro has assumed that wind projects would supply 85% of their expected output as dependable energy, compared to 66-68% for Keeyask and Conawapa[40]. However, a low water year for Keeyask or Conawapa is likely to coincide with a low water ear for the rest of Manitoba's hydro plants, whereas there is no reason to expect variations in wind output to be correlated with variations in hydro output. Adding more hydro to a hydro-dominated system increases risk; adding wind decreases it. No value is given to this in the Net Present Value calculations.x

4.5 Conclusions

Manitoba Hydro's consideration of wind in its NFAT application is flawed in several ways:

- The cost of wind is significantly over-estimated
- Potentially attractive development plans combining new wind generation to serve domestic load with increased exports were not considered
- Wind's potential for reducing risk, through just-in-time development and diversity of supply, have not been factored into the quantitative assessment

Power Advisory makes the following recommendations:

- Assumptions related to the cost of wind should be revised as follows, both in the LCOE calculation and in the quantitative assessment of the development plans:
    - New project capital cost: $1,710/kW in 2012 dollars, excluding transmission costs, declining by 0.8%/year in real terms (compounding) through 2030, with a revised construction schedule.
    - Equipment life: 25 years for wind projects (turbines etc.), 35 years for transmission stations, 50 years for transmission lines, with redevelopment of the non-transmission components costing 80% of the then-current cost of new generation.
    - Fixed O&M costs: $39.55/kW-year (in 2012 dollars), rather than the $46/kW-year used in the LCOE calculation.
    - Wind integration costs: at most $5.76/MWh (in 2012 dollars), rather than the $8.45/MWh used in the LCOE calculations.
- Additional scenarios should be developed and optimized based on new wind generation, a new intertie (exploring both 250-MW and 750-MW configurations), and postponement or cancellation of Keeyask and/or Conawapa.

[40] MH NFAT, Appendix 7.2 – Range of Resource Options, pp. 11, 44 and 54

Appendix: Adjusted Supply-Demand Balance Tables

The following tables are based on MH NFAT, Appendix 4.2 – Manitoba Hydro Supply and Demand Tables. The first set of tables is based on the “NFAT 2013 Update – No New Resources” tables on pages 120-123; the only differences from the original tables are in the DSM Forecast lines and the subsequent summary rows. The second set is the same, with the additional change of replacing the “Contracted Exports” and “Proposed Exports” rows with those from the “NFAT 2013 Update – K19/C25/750MW (WPS Sales & Inv)” tables on pages 125-128. It is intended to approximate how the export contracts under consideration could be met with no new resources other than an enhanced DSM program. These changes (but not the subsequent changes to the summary rows) are highlighted in yellow.

Date: February 4, 2014

System Firm Winter Peak Demand and Capacity Resources (MW) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3																		
	Base Supply Power Resources																			
	Existing Hydro		5,124	5,127	5,164	5,167	5,194	5,197	5,200	5,203	5,206	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209
	Existing Thermal																			
	Brandon Coal - Unit 5		105	105	105	105	105	105												
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Import		550	385	385	385	385	385	385	385	385	385	385	385						
	Proposed Imports			220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	
	Pointe du Bois Rebuild																			45
	Bipole III Reduced Losses						86	86	86	86	86	86	86	86	86	86	86	86	86	86
5	**Total Base Supply Power Resources**		**6,059**	**6,183**	**6,286**	**6,289**	**6,402**	**6,405**	**6,303**	**6,306**	**6,309**	**6,312**	**6,312**	**6,312**	**5,927**	**5,927**	**5,927**	**5,927**	**5,927**	**5,752**
6	**Total Power Resources**	4+5	**6,059**	**6,183**	**6,286**	**6,289**	**6,402**	**6,405**	**6,303**	**6,306**	**6,309**	**6,312**	**6,312**	**6,312**	**5,927**	**5,927**	**5,927**	**5,927**	**5,927**	**5,752**
	Peak Demand																			
	2013 Base Load Forecast		4,601	4,680	4,742	4,801	4,857	4,930	5,002	5,074	5,147	5,222	5,296	5,369	5,443	5,516	5,588	5,664	5,739	5,813
	Less: GAC DSM Forecast		(23)	(57)	(102)	(160)	(229)	(309)	(390)	(470)	(551)	(631)	(712)	(793)	(874)	(954)	(1,035)	(1,116)	(1,197)	(1,279)
7	**Manitoba Net Load**		4,578	4,623	4,640	4,641	4,628	4,621	4,612	4,604	4,596	4,591	4,584	4,576	4,569	4,562	4,553	4,548	4,542	4,534
	Contracted Exports		605	605	358	358	358	358	358	358	358	358	358	358						
	Proposed Exports				55	55	55	55	55											
8	**Total Exports**		605	605	413	413	413	413	413	358	358	358	358	358						
9	**Total Peak Demand**	7+8	**5,183**	**5,228**	**5,053**	**5,054**	**5,041**	**5,034**	**5,025**	**4,962**	**4,954**	**4,949**	**4,942**	**4,934**	**4,569**	**4,562**	**4,553**	**4,548**	**4,542**	**4,534**
10	Reserves		483	510	562	567	572	579	586	594	601	609	618	626	634	643	651	660	669	678
11	**System Surplus/(Deficit)**	6-9-10	**393**	**445**	**671**	**668**	**789**	**792**	**692**	**750**	**754**	**754**	**752**	**752**	**724**	**722**	**723**	**719**	**716**	**540**
12	Less: Brandon Unit 5		(105)	(105)	(105)	(105)	(105)	(105)												
	Exportable Surplus	11+12	**288**	**340**	**566**	**563**	**684**	**687**	**692**	**750**	**754**	**754**	**752**	**752**	**724**	**722**	**723**	**719**	**716**	**540**

Date: February 4, 2014

System Firm Winter Peak Demand and Capacity Resources (MW) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3																		
	Base Supply Power Resources																			
	Existing Hydro		5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Import																			
	Proposed Imports																			
	Pointe du Bois Rebuild		45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Bipole III Reduced Losses		86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
5	**Total Base Supply Power Resources**		**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**
6	**Total Power Resources**	4+5	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**
	Peak Demand																			
	2013 Base Load Forecast		5,886	5,959	6,032	6,105	6,178	6,251	6,324	6,396	6,469	6,542	6,615	6,688	6,761	6,834	6,907	6,979	7,052	7,125
	Less: GAC DSM Forecast		(1,360)	(1,441)	(1,522)	(1,604)	(1,685)	(1,767)	(1,848)	(1,930)	(2,011)	(2,093)	(2,175)	(2,256)	(2,338)	(2,420)	(2,502)	(2,584)	(2,665)	(2,747)
7	**Manitoba Net Load**		4,526	4,518	4,510	4,501	4,493	4,484	4,476	4,466	4,458	4,449	4,440	4,432	4,423	4,414	4,405	4,395	4,387	4,378
	Contracted Exports																			
	Proposed Exports																			
8	**Total Exports**																			
9	**Total Peak Demand**	7+8	**4,526**	**4,518**	**4,510**	**4,501**	**4,493**	**4,484**	**4,476**	**4,466**	**4,458**	**4,449**	**4,440**	**4,432**	**4,423**	**4,414**	**4,405**	**4,395**	**4,387**	**4,378**
10	Reserves		687	696	705	715	724	734	743	753	762	772	781	791	799	808	817	826	834	843
11	**System Surplus/(Deficit)**	6-9-10	**539**	**538**	**537**	**536**	**535**	**534**	**533**	**533**	**532**	**531**	**531**	**529**	**530**	**530**	**530**	**531**	**531**	**531**
12	Less: Brandon Unit 5																			
	Exportable Surplus	11+12	**539**	**538**	**537**	**536**	**535**	**534**	**533**	**533**	**532**	**531**	**531**	**529**	**530**	**530**	**530**	**531**	**531**	**531**

Date: February 4, 2014

System Firm Energy Demand and Dependable Resources (GWh) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**New Wind**																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21,914	21,912	21,911	21,899	21,888	21,880	21,862	21,854	21,846	21,838	21,838	21,828	21,818	21,818	21,808	21,798	21,798	21,788
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	811	592											
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354
	Contracted Import		2,705	1,949	1,549	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	271					
	Proposed Imports			781	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	155
	Hydro Adjustment		340	373	784	844	844	844	844	844	844	844	844	844	406	307	307	307	307	70
	Market Purchases		363	338	583	493	493	493	493	493	493	493	493	493	1,861	2,132	2,132	2,132	2,132	2,913
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild																			60
	Bipole III Reduced Losses						190	190	190	190	190	190	190	190	190	190	190	190	190	190
6	**Total Base Supply Power Resources**		**30,211**	**30,242**	**30,652**	**30,700**	**30,879**	**30,871**	**30,634**	**30,034**	**30,026**	**30,018**	**30,018**	**30,008**	**29,560**	**29,461**	**29,451**	**29,441**	**29,441**	**29,254**
7	**Total Power Resources**	5+6	**30,211**	**30,242**	**30,652**	**30,700**	**30,879**	**30,871**	**30,634**	**30,034**	**30,026**	**30,018**	**30,018**	**30,008**	**29,560**	**29,461**	**29,451**	**29,441**	**29,441**	**29,254**
	Manitoba Domestic Load																			
	2013 Base Load Forecast		25,239	25,676	26,013	26,322	26,606	27,003	27,398	27,789	28,197	28,605	29,013	29,418	29,822	30,225	30,625	31,041	31,453	31,863
	Construction Power - Hydro															4	12	16	28	8
	Less: GAC DSM Forecast		(108)	(269)	(487)	(761)	(1,089)	(1,472)	(1,855)	(2,238)	(2,621)	(3,005)	(3,389)	(3,773)	(4,158)	(4,543)	(4,928)	(5,314)	(5,699)	(6,086)
8	**Manitoba Net Load**		25,131	25,407	25,526	25,561	25,517	25,531	25,543	25,551	25,576	25,600	25,624	25,645	25,664	25,686	25,709	25,743	25,782	25,785
	Contracted Exports		3,156	3,156	2,115	2,012	2,012	2,012	2,012	2,012	2,012	2,012	2,012	2,012	249	145	145	145	145	145
	Proposed Exports				394	414	414	414	414	204	162	162	162	162	162	162	162	162	162	
	Less: Adverse Water				(309)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(61)					
9	**Total Exports**		3,156	3,156	2,200	2,056	2,056	2,056	2,056	1,846	1,804	1,804	1,804	1,804	350	307	307	307	307	145
10	**Total Energy Demand**	8+9	**28,287**	**28,563**	**27,726**	**27,617**	**27,573**	**27,587**	**27,599**	**27,397**	**27,380**	**27,404**	**27,428**	**27,449**	**26,014**	**25,993**	**26,016**	**26,050**	**26,089**	**25,930**
11	**System Surplus/(Deficit)**	7-10	**1,924**	**1,679**	**2,926**	**3,083**	**3,306**	**3,284**	**3,035**	**2,637**	**2,646**	**2,614**	**2,590**	**2,559**	**3,546**	**3,468**	**3,435**	**3,391**	**3,352**	**3,324**
12	Less: Brandon Unit 5		(811)	(811)	(811)	(811)	(811)	(811)	(592)											
13	Adverse Water				(309)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(61)					
	Exportable Surplus	11+12+13	**1,113**	**868**	**1,806**	**1,902**	**2,125**	**2,103**	**2,073**	**2,267**	**2,276**	**2,244**	**2,220**	**2,189**	**3,485**	**3,468**	**3,435**	**3,391**	**3,352**	**3,324**

Date: February 4, 2014

System Firm Energy Demand and Dependable Resources (GWh) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

#	Fiscal Year		2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**New Wind**																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21,788	21,778	21,768	21,768	21,758	21,748	21,748	21,738	21,738	21,728	21,718	21,718	21,708	21,698	21,698	21,688	21,678	21,678
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354
	Contracted Import																			
	Proposed Imports																			
	Hydro Adjustment																			
	Market Purchases		3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild		150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Bipole III Reduced Losses		190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
6	**Total Base Supply Power Resources**		**29,274**	**29,264**	**29,254**	**29,254**	**29,244**	**29,234**	**29,234**	**29,224**	**29,224**	**29,214**	**29,204**	**29,204**	**29,194**	**29,184**	**29,184**	**29,174**	**29,164**	**29,164**
7	**Total Power Resources**	5+6	**29,274**	**29,264**	**29,254**	**29,254**	**29,244**	**29,234**	**29,234**	**29,224**	**29,224**	**29,214**	**29,204**	**29,204**	**29,194**	**29,184**	**29,184**	**29,174**	**29,164**	**29,164**
	Manitoba Domestic Load																			
	2013 Base Load Forecast		32,265	32,667	33,069	33,471	33,873	34,274	34,676	35,078	35,480	35,882	36,283	36,685	37,087	37,489	37,890	38,292	38,694	39,096
	Construction Power - Hydro		8	4																
	Less: GAC DSM Forecast		(6,472)	(6,859)	(7,246)	(7,634)	(8,021)	(8,409)	(8,797)	(9,185)	(9,574)	(9,962)	(10,351)	(10,740)	(11,129)	(11,519)	(11,908)	(12,298)	(12,688)	(13,078)
8	**Manitoba Net Load**		25,801	25,812	25,823	25,837	25,852	25,865	25,879	25,893	25,906	25,920	25,932	25,945	25,958	25,970	25,982	25,994	26,006	26,018
	Contracted Exports		145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
	Proposed Exports																			
	Less: Adverse Water																			
9	**Total Exports**		145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
10	**Total Energy Demand**	8+9	**25,946**	**25,957**	**25,968**	**25,982**	**25,997**	**26,010**	**26,024**	**26,038**	**26,051**	**26,065**	**26,077**	**26,090**	**26,103**	**26,115**	**26,127**	**26,139**	**26,151**	**26,163**
11	**System Surplus/(Deficit)**	7-10	**3,328**	**3,307**	**3,286**	**3,272**	**3,247**	**3,224**	**3,210**	**3,186**	**3,173**	**3,149**	**3,127**	**3,114**	**3,091**	**3,069**	**3,057**	**3,035**	**3,013**	**3,001**
12	Less: Brandon Unit 5																			
13	Adverse Water																			
	Exportable Surplus	11+12+13	**3,328**	**3,307**	**3,286**	**3,272**	**3,247**	**3,224**	**3,210**	**3,186**	**3,173**	**3,149**	**3,127**	**3,114**	**3,091**	**3,069**	**3,057**	**3,035**	**3,013**	**3,001**

Date: February 4, 2014

System Firm Winter Peak Demand and Capacity Resources (MW) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3																		
	Base Supply Power Resources																			
	Existing Hydro		5,124	5,127	5,164	5,167	5,194	5,197	5,200	5,203	5,206	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209
	Existing Thermal																			
	Brandon Coal - Unit 5		105	105	105	105	105	105												
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Import		550	385	385	385	385	385	385	385	385	385	385	385						
	Proposed Imports			220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	
	Pointe du Bois Rebuild																			45
	Bipole III Reduced Losses						86	86	86	86	86	86	86	86	86	86	86	86	86	86
5	**Total Base Supply Power Resources**		**6,059**	**6,183**	**6,286**	**6,289**	**6,402**	**6,405**	**6,303**	**6,306**	**6,309**	**6,312**	**6,312**	**6,312**	**5,927**	**5,927**	**5,927**	**5,927**	**5,927**	**5,752**
6	**Total Power Resources**	4+5	**6,059**	**6,183**	**6,286**	**6,289**	**6,402**	**6,405**	**6,303**	**6,306**	**6,309**	**6,312**	**6,312**	**6,312**	**5,927**	**5,927**	**5,927**	**5,927**	**5,927**	**5,752**
	Peak Demand																			
	2013 Base Load Forecast		4,601	4,680	4,742	4,801	4,857	4,930	5,002	5,074	5,147	5,222	5,296	5,369	5,443	5,516	5,588	5,664	5,739	5,813
	Less: GAC DSM Forecast		(23)	(57)	(102)	(160)	(229)	(309)	(390)	(470)	(551)	(631)	(712)	(793)	(874)	(954)	(1,035)	(1,116)	(1,197)	(1,279)
7	**Manitoba Net Load**		4,578	4,623	4,640	4,641	4,628	4,621	4,612	4,604	4,596	4,591	4,584	4,576	4,569	4,562	4,553	4,548	4,542	4,534
	Contracted Exports		605	605	358	358	358	358	358	633	880	880	880	880	385	385	275	275	275	275
	Proposed Exports			119	174	174	174	174	174	119						220	330	330	330	330
8	**Total Exports**		605	724	532	532	532	532	532	752	880	880	880	880	385	605	605	605	605	605
9	**Total Peak Demand**	7+8	**5,183**	**5,347**	**5,172**	**5,173**	**5,160**	**5,153**	**5,144**	**5,356**	**5,476**	**5,471**	**5,464**	**5,456**	**4,954**	**5,167**	**5,158**	**5,153**	**5,147**	**5,139**
10	Reserves		483	510	562	567	572	579	586	594	601	609	618	626	634	643	651	660	669	678
11	**System Surplus/(Deficit)**	6-9-10	**393**	**326**	**552**	**549**	**670**	**673**	**573**	**356**	**232**	**232**	**230**	**230**	**339**	**117**	**118**	**114**	**111**	**(65)**
12	Less: Brandon Unit 5		(105)	(105)	(105)	(105)	(105)	(105)												
	Exportable Surplus	11+12	**288**	**221**	**447**	**444**	**565**	**568**	**573**	**356**	**232**	**232**	**230**	**230**	**339**	**117**	**118**	**114**	**111**	

Date: February 4, 2014

System Firm Winter Peak Demand and Capacity Resources (MW) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**Total New Power Resources**	1+2+3																		
	Base Supply Power Resources																			
	Existing Hydro		5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209	5,209
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Import																			
	Proposed Imports																			
	Pointe du Bois Rebuild		45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
	Bipole III Reduced Losses		86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
5	**Total Base Supply Power Resources**		**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**
6	**Total Power Resources**	4+5	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**	**5,752**
	Peak Demand																			
	2013 Base Load Forecast		5,886	5,959	6,032	6,105	6,178	6,251	6,324	6,396	6,469	6,542	6,615	6,688	6,761	6,834	6,907	6,979	7,052	7,125
	Less: GAC DSM Forecast		(1,360)	(1,441)	(1,522)	(1,604)	(1,685)	(1,767)	(1,848)	(1,930)	(2,011)	(2,093)	(2,175)	(2,256)	(2,338)	(2,420)	(2,502)	(2,584)	(2,665)	(2,747)
7	**Manitoba Net Load**		4,526	4,518	4,510	4,501	4,493	4,484	4,476	4,466	4,458	4,449	4,440	4,432	4,423	4,414	4,405	4,395	4,387	4,378
	Contracted Exports		275	275	275	275														
	Proposed Exports		330	330	330	330	330													
8	**Total Exports**		605	605	605	605	330													
9	**Total Peak Demand**	7+8	**5,131**	**5,123**	**5,115**	**5,106**	**4,823**	**4,484**	**4,476**	**4,466**	**4,458**	**4,449**	**4,440**	**4,432**	**4,423**	**4,414**	**4,405**	**4,395**	**4,387**	**4,378**
10	Reserves		687	696	705	715	724	734	743	753	762	772	781	791	799	808	817	826	834	843
11	**System Surplus/(Deficit)**	6-9-10	**(66)**	**(67)**	**(68)**	**(69)**	**205**	**534**	**533**	**533**	**532**	**531**	**531**	**529**	**530**	**530**	**530**	**531**	**531**	**531**
12	Less: Brandon Unit 5																			
	Exportable Surplus	11+12					**205**	**534**	**533**	**533**	**532**	**531**	**531**	**529**	**530**	**530**	**530**	**531**	**531**	**531**

Date: February 4, 2014

System Firm Energy Demand and Dependable Resources (GWh) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

#	Fiscal Year		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**New Wind**																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21,914	21,912	21,911	21,899	21,888	21,880	21,862	21,854	21,846	21,838	21,838	21,828	21,818	21,818	21,808	21,798	21,798	21,788
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	811	592											
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354
	Contracted Import		2,705	1,949	1,549	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	271					
	Proposed Imports			781	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	155
	Hydro Adjustment		340	373	784	844	844	844	844	844	844	844	844	844	406	307	307	307	307	70
	Market Purchases		363	338	583	493	493	493	493	493	493	493	493	493	1,861	2,132	2,132	2,132	2,132	2,913
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild																			60
	Bipole III Reduced Losses						190	190	190	190	190	190	190	190	190	190	190	190	190	190
6	**Total Base Supply Power Resources**		**30,211**	**30,242**	**30,652**	**30,700**	**30,879**	**30,871**	**30,634**	**30,034**	**30,026**	**30,018**	**30,018**	**30,008**	**29,560**	**29,461**	**29,451**	**29,441**	**29,441**	**29,254**
7	**Total Power Resources**	5+6	**30,211**	**30,242**	**30,652**	**30,700**	**30,879**	**30,871**	**30,634**	**30,034**	**30,026**	**30,018**	**30,018**	**30,008**	**29,560**	**29,461**	**29,451**	**29,441**	**29,441**	**29,254**
	Manitoba Domestic Load																			
	2013 Base Load Forecast		25,239	25,676	26,013	26,322	26,606	27,003	27,398	27,789	28,197	28,605	29,013	29,418	29,822	30,225	30,625	31,041	31,453	31,863
	Construction Power - Hydro															4	12	16	28	8
	Less: GAC DSM Forecast		(108)	(269)	(487)	(761)	(1,089)	(1,472)	(1,855)	(2,238)	(2,621)	(3,005)	(3,389)	(3,773)	(4,158)	(4,543)	(4,928)	(5,314)	(5,699)	(6,086)
8	**Manitoba Net Load**		25,131	25,407	25,526	25,561	25,517	25,531	25,543	25,551	25,576	25,600	25,624	25,645	25,664	25,686	25,709	25,743	25,782	25,785
	Contracted Exports		3,156	3,156	2,115	2,012	2,012	2,012	2,012	3,048	4,191	4,314	4,314	4,314	2,031	1,887	1,472	1,389	1,389	1,389
	Proposed Exports			448	931	952	952	952	952	742	252	162	162	162	162	991	1,572	1,655	1,655	1,493
	Less: Adverse Water				(309)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(61)					
9	**Total Exports**		3,156	3,604	2,737	2,594	2,594	2,594	2,594	3,420	4,073	4,106	4,106	4,106	2,132	2,878	3,044	3,044	3,044	2,882
10	**Total Energy Demand**	8+9	**28,287**	**29,011**	**28,263**	**28,155**	**28,111**	**28,125**	**28,137**	**28,971**	**29,649**	**29,706**	**29,730**	**29,751**	**27,796**	**28,564**	**28,753**	**28,787**	**28,826**	**28,667**
11	**System Surplus/(Deficit)**	7-10	**1,924**	**1,231**	**2,389**	**2,545**	**2,768**	**2,746**	**2,497**	**1,063**	**377**	**312**	**288**	**257**	**1,764**	**897**	**698**	**654**	**615**	**587**
12	Less: Brandon Unit 5		(811)	(811)	(811)	(811)	(811)	(811)	(592)											
13	Adverse Water				(309)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(61)					
	Exportable Surplus	11+12+13	**1,113**	**420**	**1,269**	**1,364**	**1,587**	**1,565**	**1,535**	**693**	**7**				**1,703**	**897**	**698**	**654**	**615**	**587**

Date: February 4, 2014

System Firm Energy Demand and Dependable Resources (GWh) @ Generation
NFAT 2013 Update
No New Resources - GAC DSM Forecast

	Fiscal Year		2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Imports																			
	Contracted																			
	Proposed																			
3	**Total New Imports**																			
4	**New Wind**																			
5	**Total New Power Resources**	1+2+3+4																		
	Base Supply Power Resources																			
	Existing Hydro		21,788	21,778	21,768	21,768	21,758	21,748	21,748	21,738	21,738	21,728	21,718	21,718	21,708	21,698	21,698	21,688	21,678	21,678
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354
	Contracted Import																			
	Proposed Imports																			
	Hydro Adjustment																			
	Market Purchases		3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068	3,068
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild		150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Bipole III Reduced Losses		190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
6	**Total Base Supply Power Resources**		**29,274**	**29,264**	**29,254**	**29,254**	**29,244**	**29,234**	**29,234**	**29,224**	**29,224**	**29,214**	**29,204**	**29,204**	**29,194**	**29,184**	**29,184**	**29,174**	**29,164**	**29,164**
7	**Total Power Resources**	5+6	**29,274**	**29,264**	**29,254**	**29,254**	**29,244**	**29,234**	**29,234**	**29,224**	**29,224**	**29,214**	**29,204**	**29,204**	**29,194**	**29,184**	**29,184**	**29,174**	**29,164**	**29,164**
	Manitoba Domestic Load																			
	2013 Base Load Forecast		32,265	32,667	33,069	33,471	33,873	34,274	34,676	35,078	35,480	35,882	36,283	36,685	37,087	37,489	37,890	38,292	38,694	39,096
	Construction Power - Hydro		8	4																
	Less: GAC DSM Forecast		(6,472)	(6,859)	(7,246)	(7,634)	(8,021)	(8,409)	(8,797)	(9,185)	(9,574)	(9,962)	(10,351)	(10,740)	(11,129)	(11,519)	(11,908)	(12,298)	(12,688)	(13,078)
8	**Manitoba Net Load**		25,801	25,812	25,823	25,837	25,852	25,865	25,879	25,893	25,906	25,920	25,932	25,945	25,958	25,970	25,982	25,994	26,006	26,018
	Contracted Exports		1,389	1,389	1,389	1,389	353	145	145	145	145	145	145	145	145	145	145	145	145	145
	Proposed Exports		1,493	1,493	1,493	1,493	1,493	249												
	Less: Adverse Water																			
9	**Total Exports**		2,882	2,882	2,882	2,882	1,846	394	145	145	145	145	145	145	145	145	145	145	145	145
10	**Total Energy Demand**	8+9	**28,683**	**28,694**	**28,705**	**28,719**	**27,698**	**26,259**	**26,024**	**26,038**	**26,051**	**26,065**	**26,077**	**26,090**	**26,103**	**26,115**	**26,127**	**26,139**	**26,151**	**26,163**
11	**System Surplus/(Deficit)**	7-10	**591**	**570**	**549**	**535**	**1,546**	**2,975**	**3,210**	**3,186**	**3,173**	**3,149**	**3,127**	**3,114**	**3,091**	**3,069**	**3,057**	**3,035**	**3,013**	**3,001**
12	Less: Brandon Unit 5																			
13	Adverse Water																			
	Exportable Surplus	11+12+13	**591**	**570**	**549**	**535**	**1,546**	**2,975**	**3,210**	**3,186**	**3,173**	**3,149**	**3,127**	**3,114**	**3,091**	**3,069**	**3,057**	**3,035**	**3,013**	**3,001**