Manitoba Hydro

Book of Documents

GAC cross

TAB 1

> 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.

[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.

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.

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

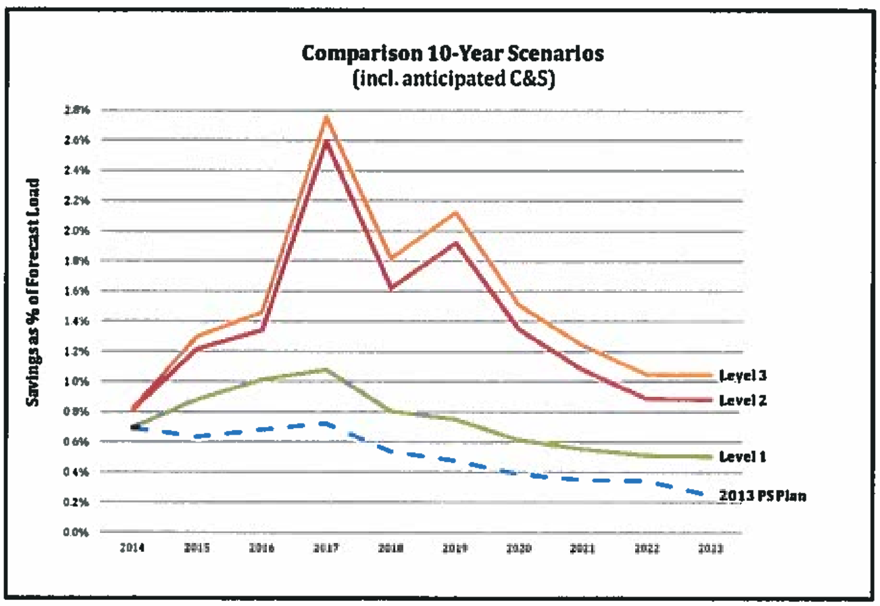
[39] MH NFAT, Chapter 6 – The Window of Opportunity, Table 6.4, p. 28 lists six contracts which are contingent on new hydro development, with four of them being specifically contingent on Keeyask.

6

TAB 2

		2014	2015	2016	2017	2018	2019	10 YEAR AVG (programs only)	10-yr Avg. (prog's + C&S)
Level 1 0.5%	%/yr	0.4%	0.6%	0.7%	0.6%	0.5%	0.5%	0.5%	0.7%
	GWh/yr	110	180	170	167	138	137	[illegible] GW.h/yr (cumulative)	1,918 GW.h/yr (cumulative)
Level 2 1.1%	%/yr	0.5%	1.0%	1.0%	2.1%	1.3%	1.6%	1.1%	1.3%
	GWh/yr	138	244	255	559	352	445	[illegible] GW.h/yr (cumulative)	3,104 GW.h/yr (cumulative)
Level 3 1.2%	%/yr	0.6%	1.0%	1.1%	2.3%	1.5%	1.8%	1.2%	1.5%
	GWh/yr	141	266	285	601	403	499	[illegible] GW.h/yr (cumulative)	3,478 GW.h/yr (cumulative)

The following figure illustrates the cumulative savings of the enhanced levels of DSM as a percentage of load reduction compared to Manitoba Hydro's 2013 Power Smart Plan.



The enhanced levels of DSM represent a significant potential reduction to Manitoba Hydro's load forecast. The following figure presents graphically the 2013 Forecast adjusted for the enhanced levels of DSM examined.

A separate report prepared by Helimax[60] for Manitoba Hydro focused on the St. Leon/Darlingford area and explored the Manitoba Hydro system impacts of installing 1000 MW of nameplate wind capacity in this area. The capacity factors associated with a large expansion of wind generation in this specific area were also studied. The report provides estimated capacity factors based on utilization of two different technologies at seven sites in this area, the General Electric GE 1.5sle wind turbine and Mitsubishi MWT95/2.4 wind turbine. These capacity factors are provided in Table 2. Table 2 shows that within a specific area the capacity factor decreases as less productive sites are developed.

Table 2: Average Wind Speeds and Capacity Factors at Seven Sites in St. Leon/Darlingford Area

	Average Wind Speed at 80m	Capacity Factor At 80m (%)	
	(m/s)	GE1.5sle	MWT95/2.4
Site 1	8.0	37.4	36.1
Site 2	7.8	36.4	35.1
Site 3	7.7	35.7	34.3
Site 4	7.8	35.9	34.9
Site 5	7.5	34.5	33.1
Site 6	7.3	30.7	29.2
Site 7	7.8	37.1	35.7

With the exception of Site 6 that exhibits Wind Class 3 characteristics, all other sites in Table 2 can be classified as Wind Class 4. Given the potential for increased efficiency of wind turbines and related components, Black & Veatch[61] have forecast future improvements for onshore wind capacity factors between 2010 and 2050 based on the wind class of a site.

[60] Helimax Energy Inc. (2008), Generation of Power Production Time Series, Seven Virtual Wind Projects in Manitoba

[61] Black & Veatch (2012), Cost Report Cost and Performance Data for Power Generation Technologies, pg. 46.

TAB 3

Focused on What Matters Most:

Manitoba's Clean Energy Strategy

Manitoba

9

⑤ FREEDOM FROM FOSSIL FUELS

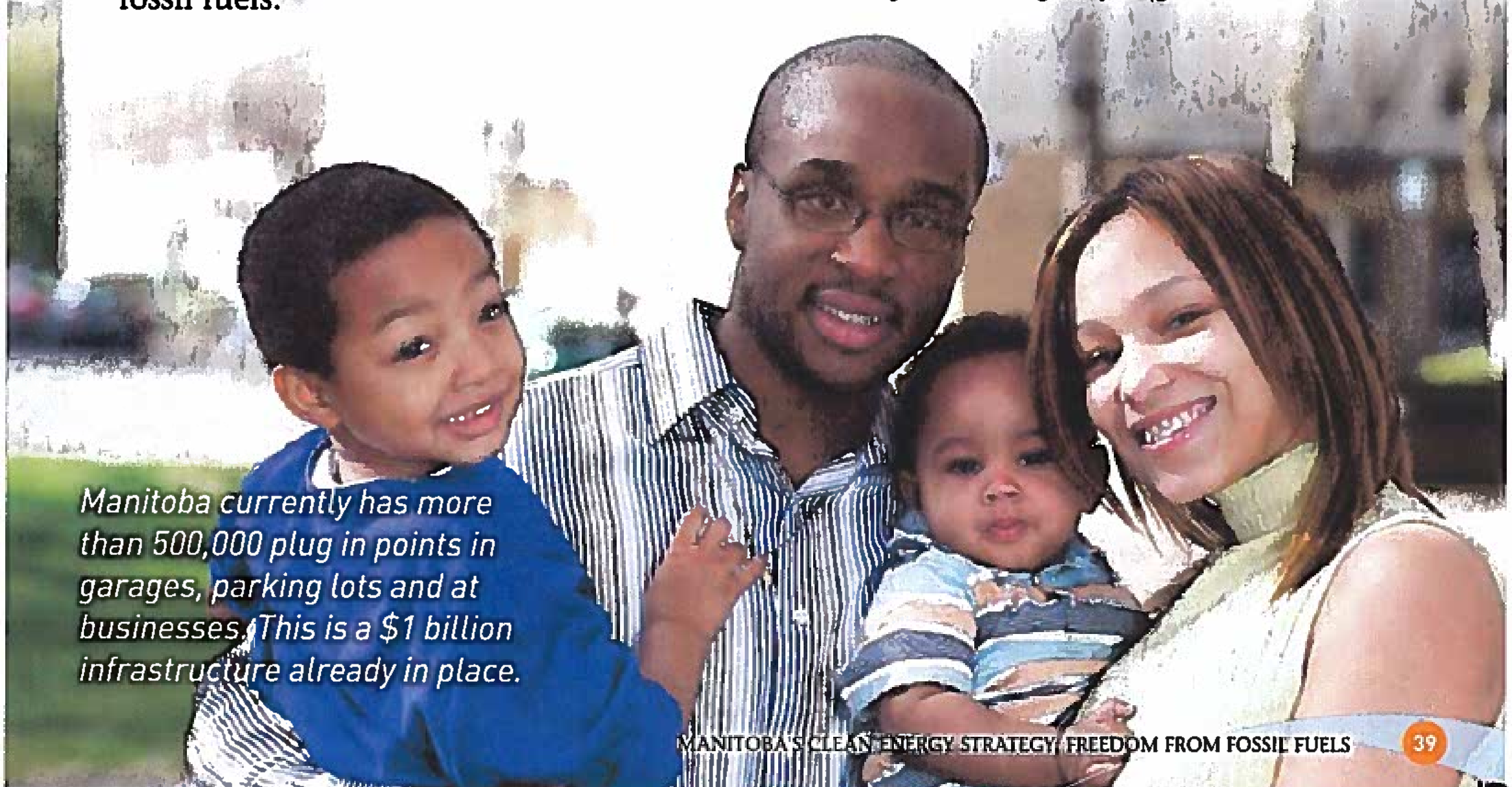
Over the coming years, a number of Manitobans will be among the first in the industrial world to live their lives without requiring substantial quantities of fossil fuels. Instead, they can meet the vast majority of their three core, daily, energy needs (for electricity, heat and transportation) by using clean, renewable energy and by being energy efficient – not by burning coal, natural gas, gasoline or diesel. These first fossil fuel free Manitobans will be pioneering a path that most nations are hoping their citizens will get to take in future decades – toward a daily life no longer dependent on fossil fuels.

These Manitobans will achieve fossil fuel freedom through a simple three-step process:

1. Their electricity from Manitoba Hydro will already be clean, more than 98 per cent or more fossil fuel free. It will supply their lighting, appliances and other power needs. A clean electricity supply, though difficult to obtain in most other nations, is already here for Manitobans.

2. Their heat will be provided – as it already is for thousands of Manitobans – through clean, renewable, energy systems (ex: heat pumps, biomass, solar), which eliminate the need for fossil fuels like natural gas. While all electric heat is also fossil free, heat pumps use 50 per cent to 70 per cent less electricity, so they're a more efficient choice.

3. The biggest step for most Manitobans will be in transportation. An option chosen by some will be to buy an electric or plug-in hybrid vehicle, which will shift their vehicle energy over to clean electricity, while cutting their gasoline use by 65 per cent to 100 per cent. Others may choose to cut their fossil fuel use by taking public transit, car pooling or ride sharing, while others opt for walking or cycling.



Manitoba currently has more than 500,000 plug in points in garages, parking lots and at businesses. This is a $1 billion infrastructure already in place.

10

Taken together, these Manitobans will have effectively reduced their use of fossil fuels by more than 90 per cent across the three major energy end uses. They will also have begun to generate a range of benefits for themselves, the environment and the Manitoban economy:

- By moving off gasoline, they will slash their pump price worries and gain the lowest cost vehicle fuel in North America – electricity from Manitoba Hydro at approximately the equivalent of 12 cents per litre.
- By changing to heat pumps and electric and plug-in hybrid vehicles, they will save $3,000 to $5,000 in fuel costs each year. Over a lifetime, this can reach to well over $100,000 per family.
- They will cut their direct GHGs to residual levels (zero to two tonnes.) This can be compared to today's families in North Dakota or Saskatchewan, many of whom emit 15 to 40 tonnes of GHGs a year by using coal fired power, gas heat and gasoline.

When a two gasoline driven vehicle family shifts to using two electric vehicles, they can expect to save more than $100,000 over their lifetimes in vehicle fuel costs.

Fossil Fuel Freedom – A Movement Towards a Healthy Future

Many nations can only set fossil fuel freedom as a visionary goal, for the years 2040 or 2050.

But in Manitoba, a significant number of its citizens can choose to achieve this freedom today. Any such transition, as we have seen, would require decades to move through a society's energy infrastructure. For example, our vehicle fleets alone requires 15 to 20 years to turn over; our furnaces and heating systems require 20 to 30 years; and our building stock and energy generating infrastructure can last another 50 to 100 years.

Nonetheless, for most Manitobans, the opportunity to move from conventional fossil fuel use to clean energy, and even on to fossil fuel freedom is increasingly a reality. More and more Manitobans are taking the quiet steps they need to ensure that their lives are less exposed to the risks and costs of fossil fuels.

And the reason Manitobans are so well positioned to make this transition, and able to consider it now, in an atmosphere free of any particular energy crisis, is because of the strong clean energy economy and infrastructure which we have come together to create, starting decades ago.

But today's good news is that for Manitobans, the fossil fuel free future starts here…and it starts now.

TAB 4

DSM Analysis – 3 Additional Levels

What level of DSM is economic?

	Total Resource Cost Without Pipeline Load Includes all costs and does not account for changes in Domestic revenue [with pipeline load for level 2 to level 3 only] Incremental NPV (millions of 2014$) of implementing higher level of DSM		
	All Gas	K19/Gas/750MW	K19/C/750MW
Base to Level 1	535	497	285
Level 1 to Level 2	816	887	737
Level 2 to Level 3 [with pipeline]	-49 [-60]	-86 [-39]	-102 [-85]

Note: ISD changes with Level of DSM for Conawapa (DSM1:2030, DSM2:2031, DSM3:2033) and All Gas (DSM1:2028, DSM2:2031, DSM3:2033).

TAB 5

NEEDS FOR AND ALTERNATIVES TO (NFAT)

Request of Manitoba Hydro Regarding the Evidence of Mr. Thomson

Assuming flat load, 750 MW line, Keeyask & existing & new contracts extended into the future, what would the NPV be in that circumstance?

Response:

The assumption of flat load growth beyond 2022/23 results in a hypothetical circumstance.

The analysis of this hypothetical circumstance uses the economic output from existing reference cases which require new resources in 2023/24 (2013 planning assumptions and updated Keeyask capital costs), and the following additional assumptions:

- The no new generation case was based on the All Gas plan up to and including 2022/23, with existing export commitments beyond 2022/23 based on contract terms and conditions.
- The Keeyask & 750MW interconnection case was based on Plan 5 K19/Gas25/750MW (WPS Sales only) up to and including 2022/23, with existing export commitments beyond 2022/23 based on contract terms and conditions.
- No domestic load growth (flat load) beyond 2022/23.
- From 2023/24 to 2048/49 all energy volumes were held constant.
- Beyond 2048/49, the long-life asset evaluation methodology was applied.

As shown in the following table, if there is no load growth assumed beyond 2022/23 and surplus energy is valued using the 2013 long-term price forecast, building Keeyask and a new interconnection results in an incremental net present value of $395M (at real WACC of 5.4%) relative to building no new generation. This analysis is considered conservative from an export power pricing perspective because it values uncommitted dependable surplus energy at the long-term dependable export price forecast rather than using values consistent with recently signed contracts.

	Present Valued at a real WACC of 5.4%		
	Capital Costs PV Millions 2014$	Revenue PV Million 2014$	Revenues – Costs NPV Millions 2014$
No new Generation	0	3160	3160
Keeyask 2019 & 750MW interconnection	4605	8167	3563
Incremental NPV			402

The following table shows the same evaluation with the return on equity of 3% removed resulting in a real WACC of 4.65%. As shown in the table there is an incremental net present value $1178M (at real WACC of 4.65%) relative to building no new generation.

	Present Valued at a real WACC of 4.65%		
	Capital Costs PV Millions 2014$	Revenue PV Million 2014$	Revenues – Costs NPV Millions 2014$
No new Generation	0	3675	3675
Keeyask & 750MW interconnection	4816	9681	4865
Incremental NPV			1190

Although not provided in this anlaysis, there would be substantial incremental benefits from transfers to the province related to Keeyask and a new interconnection.

The remainder of the response to this information request requires provision of Commercially Sensitive Information and will be filed in confidence with the PUB.

TAB 6

Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba

MANITOBA HYDRO

August 2012

Manitoba Hydro

EXECUTIVE SUMMARY

This report outlines the economic, load and environmental impacts of using electricity (including geothermal technology) instead of using natural gas for space and water heating purposes. The economic impact is assessed from the customer's and the utility's perspective along with a high level assessment of provincial leakage (i.e. the net impact of changes to extra-provincial natural gas purchases and electricity export sales). The environmental (greenhouse gas emission) impact is assessed from both a provincial and a global perspective. The scope of this assessment does not consider future uncertainty associated with a number of influential factors, including potential electricity rate structure changes (e.g. inverted rates) and potential changing Canadian and US government policies related to greenhouse gas (GHG) emissions. The assessment also does not account for any costs which may result from large-scale upgrading of Manitoba Hydro's electrical infrastructure due to significant energy demand changes.

Space Heating

The following table summarizes the load, economic and environmental impacts of using electricity instead of natural gas for space heating in a typical Manitoba residential home. Impacts are analyzed over the life of the equipment (i.e. 25 years). Values in brackets indicate a negative impact from an economic perspective and represent a reduction in GHG emissions from an environmental perspective.

Impact of Converting from Natural Gas to Electric Space Heat

Average Residential Home from Natural Gas to:	Electric Furnace	Geothermal (SCOP 2.5)
Annual Energy Load Impact		
Electric Load Impact (kW.h)	16,391	6,556
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)
Economic Impact		
Utility Perspective (Electric)	($3,223)	($1,563)
Utility Perspective (Natural Gas)	($4,107)	($4,107)
Customer Perspective	($7,737)	($11,276)
Integrated Utility / Customer Perspective	($15,067)	($16,946)
Net Provincial Inflow (Leakage)	($6,271)	$1,061*
Annual Environmental Impact		
Manitoba (kg CO_2e/year)	(3,374)	(3,374)
US - MISO Region** (kg CO_2e/year)	0 to 12,293	0 to 4,917
Net Global**(kg CO_2e/year)	(3,374) to 8,919	(3,374) to 1,543

**The provincial inflow benefits will be offset by higher cost of geothermal units relative to the cost of natural gas furnaces and air conditioners (i.e. estimated at $2,000 to $3,000).*

***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

From the customer, utility and provincial leakage perspectives, there are substantive benefits when customers use natural gas rather than electricity for space heating purposes. The directional impact for each of these factors are also the same when using natural gas for space heating relative to using geothermal systems, except for the provincial leakage impact. In the latter case, a more complete analysis would need to account for the higher cost of geothermal furnace units which are imported into Manitoba relative to the cost of importing natural gas furnaces and air conditioners.

Using electricity for space heating in Manitoba as opposed to natural gas will reduce GHG emissions in Manitoba; however the global GHG emissions will be higher due to reduced electricity exports from Manitoba (i.e. electricity exports would no longer displace fossil generation). In the future, the global impacts may change depending on future environmental policies (e.g. if a cap on GHG emissions was introduced within the U.S. in the future, changes in Manitoba electricity exports would potentially have no incremental impact on US GHG emissions). Given the possible future outcomes, the US and global environmental impacts are shown as a range of possible outcomes.

Water Heating

The following table summarizes the impact of using electricity instead of natural gas for water heating applications in a typical Manitoba residential home, analyzed over the life of the equipment (i.e. 10 years). Values in brackets indicate a negative impact from an economic perspective and represent a reduction in GHG emissions from an environmental perspective. The impacts are assessed for using electric hot water tanks relative to a conventional natural gas unit.

Impact of Converting from Natural Gas to Electric Water Heat

Average Residential Home from:	Conventional Gas to Electric Water Heat
Annual Energy Load Impact	
Electric Load Impact (kW.h)	3,489
Natural Gas Load Impact (cu.m)	(491)
Economic Impact	
Utility Perspective (Electric)	($10)
Utility Perspective (Natural Gas)	($317)
Customer Perspective	($727)
Integrated Utility / Customer Perspective	($1,054)
Net Provincial Inflow (Leakage)	($297)
Annual Environmental Impact	
Manitoba (kg CO_2e/year)	(933)
US - MISO Region* (kg CO_2e/year)	0 to 2,617
Net Global* (kg CO_2e/year)	(933) to 1,684

**The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

Similar to space heating, there are benefits to using natural gas relative to electricity for water heating purposes. The environmental (GHG) impacts of using electricity rather than natural gas for water heating applications are similar to space heating however the impacts are much lower on a per unit basis as the equipment uses less electricity/natural gas.

Manitoba - Fuel Choice Trends & Impacts

A trend towards more customers using electricity for space and water heating is evident in Manitoba. For water heating, a trend toward the increased use of electric water heaters is currently taking place and is forecast to continue into the future. For example, virtually 100% of the new home market is installing electric water heaters. A small shift towards the increased use of electricity for space heating is expected however this shift has been declining due primarily to the continuation of low natural gas prices.

As indicated in the following table, the impact of fuel switching from natural gas to electricity is approximately 3% of the expected 2030/31 domestic electric demand for both space and water heating and a 5% reduction in the provincial natural gas demand forecast in 2030/31.

2011 Load Forecast	Portion of 2011 Forecast Attributed to Fuel Switching 2030/31		
	Total Load Forecast	Space & Water Heating	% of Load
Net Firm Energy (GW.h)	32,465	874	3%
Total Natural Gas Sales ($10^6 m^3$)	1,924	-103	-5%

There are substantive economic impacts from the increased use of electricity (i.e. fuel switching) for heating purposes based on Manitoba Hydro's 2011 energy forecasts. The following table presents the net economic costs to the utility and to customers over a 30 year period. In addition, reduced export power revenue is not fully offset by the reduced imported natural gas purchases and is therefore expected to result in lower net provincial cash inflows.

Net Economic Costs & Provincial Leakage

2011 Forecast	Net Cost
Utility Perspective (Electric)	$132 million
Utility Perspective (Natural Gas)	$69 million
Customer Perspective	$311 million
Electricity Export Revenues	$505 million
Natural Gas Import Purchases	($251 million)
Net Provincial Leakage	$254 million

The following table provides the environmental (GHG) impact of fuel switching in space and water heating as per the 2011 forecasts.

Potential Annual GHG Impacts
(Attributed by Region due to Energy Use)

Year	Manitoba (tonnes C02e / year)	US - MISO Region* (tonnes C02e / year)	Net Global Impact* (tonnes C02e / year)
2012/13	(11,970)	38,753	26,783
2022/23	(154,166)	0 to 496,268	(154,166) to 342,102
2032/33	(203,699)	0 to 687,473	(203,699) to 483,774

** The US-MISO Region and Net Global impacts are shown within a range, which includes the impact under today's emission policies in export regions and potentially what the impacts would be under more aggressive emission policies in export regions.*

||| Hypothetical Impact of Total Conversion

The following analysis provides insight into the hypothetical maximum load impacts if all customers in Manitoba replaced their existing space and water heating equipment with an alternative natural gas, electric or geothermal system. The results simply provide a technical range of hypothetical impacts in terms of electricity and natural gas demand in Manitoba. The table provides:

- the existing electricity and natural gas load for space and water heating in Manitoba; and
- the hypothetical potential electricity and natural gas loads under extreme fuel conversion scenarios (i.e. all customers immediately fuel switch to either all natural gas use, all electric use or all geothermal use for space and water heating purposes).

Impacts are based on the electric and natural gas forecast for 2011.

Hypothetical Annual Load Impact
If All Customers in Manitoba Immediately Switched to One Type of Heating Fuel

	Natural Gas (1000 m3)	Electricity (GW.h)	Geothermal SCOP 2.5 (GW.h)
Current load situation - space heat	938,723	3,473	67
Current load situation - water heat	194,925	1,097	0
A. Immediate fuel switch to natural gas - space	1,339,429	---	---
A. Immediate fuel switch to natural gas - water	349,251	---	---
B. Immediate fuel switch to electric - space	---	11,341	67
B. Immediate fuel switch to electric - water	---	2,482	---
C. Immediate switch to geothermal - space	---	---	4,603
C. Immediate switch to geothermal - water	---	---	2,081

The magnitude of the hypothetical potential impact of all customers switching to electric space and water heating would add 7,868 GWh and 1,385 GWh respectively of annual electric load in Manitoba. Combined, this additional electric load would be equivalent to approximately two generating stations the size of Conawapa. **It is important to recognize that the implications to the utility go beyond the analysis provided within this report.** The consequence of a significant fuel switching scenario would also require a substantial investment in additional generation, transmission and distribution infrastructure. In addition, the utility would be confronted with managing a more diverse winter/summer load.

From the natural gas perspective, the remaining annual natural gas load would be 40% of the existing load and as such, the scenario would require a rate increase to the remaining natural gas customers to cover fixed costs (i.e. the fixed costs would need to be recovered from a much smaller customer base). It should be noted that the theoretical potential impact of all customers switching to natural gas space and water heating is also not possible with today's natural gas infrastructure. The implications of this theoretical scenario would also require extensive new infrastructure at an extraordinarily high cost.

The potential impacts of fuel switching in Manitoba for space and water heating can be significant. Given the economic drivers from a customer's perspective, it is unlikely that the Manitoba market will experience any overwhelming shift in space heating from natural gas to electricity, provided customers are informed on their choices. With water heating, the drivers are substantial enough that Manitoba Hydro expects to see a continued market shift from natural gas to electricity.

Manitoba Hydro recognizes the value customers place on having choice and the Corporation does not intend on mandating a specific fuel be used for space and water heating. Where appropriate, the Corporation prefers to use market intervention mechanisms (e.g. education, direct financial incentives, rate design options, etc.) to influence the market.

1.0 INTRODUCTION

This report outlines the economic, load and environmental impacts of using electricity (including geothermal technologies) instead of natural gas for space and water heating purposes. The economic impact is assessed from both the customer's and utility's perspective and includes a high level assessment of provincial leakage. The environmental (greenhouse gas emission) impact is assessed from both a provincial and global perspective. The scope of the assessment does not consider future uncertainty associated with a number of influential factors including potential electricity rate structure changes (e.g. inverted rates), electricity export price markets and potential changing Canadian and US government policies related to greenhouse gas (GHG) emissions.

The price of natural gas has a major influence on consumer's fuel choice. Prior to 2008, increased demand for natural gas combined with fears of limited supplies, drove prices upward. Colder/longer winters, increased use of natural gas for electrical generation, growth in the residential and commercial markets, the use of natural gas in Alberta oil sands production, and hurricanes Katrina and Rita, all contributed to natural gas price increases and price volatility. As the cost to heat with natural gas approached the cost to heat with electricity, customers questioned which choice was best. In 2008, Manitoba saw primary natural gas prices peak at 33¢/cu.m. However, more recently, improvements in drilling technology have made it more cost effective to access vast shale gas reservoirs across North America. This increase in economically accessible supply has contributed to a steady decrease in market prices since 2008. Lower, more stable natural gas prices are now forecast into the future and are expected to increase customer interest in natural gas as a competitive space and water heating option.

22

2.0 BACKGROUND

||| 2.1 Available Space & Water Heating Options

There are a number of different types of space and water heating systems available in the market.

Space Heating
The most common types of space heating options include:

- Natural Gas
  Natural gas space heating systems in Manitoba are predominantly forced air (furnace) systems while a small percentage uses hot water (boiler) distribution systems. Residential natural gas heating equipment is rated in Annual Fuel Utilization Efficiencies (AFUE). High efficiency condensing equipment have AFUE ratings range between 90% and 98%, while mid-efficient equipment are between 78 and 84%. Conventional equipment (pre 1992) was never rated under the AFUE test procedures, therefore a seasonal efficiency of 60% has been assumed. Recent changes in the residential building regulation in Manitoba prevent the sale of natural gas heating systems with an AFUE of less than 92%.

  For the purpose of this report, Manitoba Hydro calculates the energy consumption of home heating systems using "seasonal efficiency" estimates, to be equitable to all systems. Seasonal efficiency estimates are always slightly lower than AFUE ratings to take into consideration not only normal operating losses but also the reality that field installations are less ideal than the laboratory environment where AFUE tests are performed. Seasonal efficiency considers:
    - start-up and shut down cycling losses,
    - reduced air flow volumes due to undersized ductwork
    - lack of system maintenance (air filters etc.)
    - improper system commissioning
    - colder climate than assumed in AFUE calculation method.

- Electric
  Conventional electric space heating systems include forced air furnaces, hot water boiler systems and baseboard heating systems. All electric systems are considered 100% efficient as there are no venting/combustion losses.

- Geothermal Heat Pumps
  Geothermal heat pump systems use the thermal energy stored in the earth (ground or water) as a primary heat source/sink. These systems use electricity to undertake the heat transfer and are usually designed to use a backup heating system to meet peak heating requirements. These backup systems are typically electric furnaces which are a component of a geothermal heating unit. Although most heat pumps have a Coefficient of Performance (i.e. efficiency) rating of over 3.0 (or 300% efficient), most systems operate with a lower Seasonal Coefficient of Performance (SCOP) in the range of 2.0 – 3.0 (200-300% efficient) depending on the quality and configuration of the system. For the purposes of this analysis, performance based on a SCOP of 2.5 is presented as an average.

However, to demonstrate the impact of system configuration and quality, a sensitivity analysis assuming an improved SCOP of 3.5 is included in Section 5.1.

- Other
  This category includes a variety of heating systems utilizing fuel oil, propane, wood, etc. Typically, oil and propane systems are expensive and are rarely chosen in new construction applications.

The following tables provide an estimate of the capital and operating costs for conventional electric, natural gas and geothermal heating equipment bought, installed, and operating in an average residential home (i.e. 1,200 sq. ft. home).

The first table provides the costs to replace space heating equipment at the end of its life in an existing home, while the second table provides the capital and operating costs when installing space heating equipment for the first time in a new home. It should be noted that the capital cost associated with each system will vary considerably in the marketplace due to various factors including individual contractor bidding practices and marketing strategies. Therefore, typical low, high and average prices are provided. Prices, however, may fall outside the lower and higher bounds as some suppliers could offer extreme price variations. Prices also vary between new construction and retrofit (end of life) applications.

Annual operating costs presented below are based on rates in effect on May 1, 2012 (natural gas rate of $0.2220 per cubic metre and electric rate of $0.0677 per kilowatt hour) and the average heating requirement of all homes in Manitoba.

Space Heating: End-of-Life Replacement (Existing Homes)

System Description	Annual Operating Costs	Cost to Purchase and Install Equipment (Includes Labour, Equipment & Material Costs)		
		Low	High	Average
Natural Gas High Efficiency Forced Air Furnace *(no ductwork allowance)*	$562*	$3,500	$5,500	$4,500
Electric Forced Air Furnace *(no ductwork allowance)*	$1,110	$2,000	$3,000	$2,500
24,000 Btu/h Split System Air Conditioner (A.C.)	$50	$2,000	$3,000	$2,500
Ground Source Closed Loop Heat Pump SCOP 2.5 *(no ductwork allowance)*	$444	$15,000	$20,000	$17,500
Electrical Service and Panel Upgrade to 200 Amp Service *(required for electric & heat pump systems)*	---	$2,000	$3,000	$2,500
Average incremental capital cost of choosing electric over natural gas furnace				**$500**
Average incremental capital cost of choosing geothermal over natural gas furnace (with A.C.)				**$13,000**

** The Annual Operating Costs presented for natural gas furnaces includes the Basic Monthly Charge of $14/month.*

Space Heating: New Construction

System Description	Annual Operating Costs	Cost to Purchase and Install Equipment (Includes Labour, Equipment & Material Costs)		
		Low	High	Average
Natural Gas High Efficiency Forced Air Furnace *(no ductwork allowance)*	$562*	$3,500	$4,500	$4,000
Electric Forced Air Furnace *(no ductwork allowance)*	$1,110	$3,500	$4,500	$4,000
24,000 Btu/h Split System Air Conditioner (A.C.)	$50	$2,000	$3,000	$2,500
Ground Source Closed Loop Heat Pump SCOP 2.5 *(no ductwork allowance)*	$444	$20,000	$25,000	$22,500
Electrical Service and Panel Upgrade to 200 Amp Service *(required for electric & heat pump systems)*	---	$500	$1,000	$750
Average incremental capital cost of choosing electric over natural gas furnace				**$750**
Average incremental capital cost of choosing geothermal over natural gas furnace (with A.C.)				**$16,750**

** The Annual Operating Costs presented for natural gas furnaces includes the Basic Monthly Charge of $14/month.*

As indicated in the above tables, there are trade offs between operating and capital costs when choosing among space heating options. Geothermal systems are the most capital intensive but have the lowest operating costs. Geothermal systems can cost more than $15,000 incrementally to install when compared to a conventional natural gas heating system and air conditioner.

The price difference between a conventional natural gas and an electric heating system depends on the prices quoted by suppliers. Due to widely varying prices, either system could be higher or lower in cost. Using an average, the cost of installing an electric heating system is more expensive than natural gas by $500 for an end-of-life replacement and $750 for a new construction application (including the cost of the electrical service and panel upgrade to a 200 amp service). The operating cost of using a conventional electric heating system is also more expensive than the operating cost of a conventional natural gas heating system. This differential in operating cost also varies depending on whether the basic monthly charge for natural gas is included in the analysis.

Water Heating

The most common types of water heating options include:

- <u>Natural Gas</u>
  The majority of natural gas water heating systems use either a conventional or side vent hot water heating system. Conventional systems use a chimney for venting (usually shared use with the existing conventional or mid-efficient natural gas furnace) while side vented systems vent horizontally. Both systems operate under similar efficiencies (57% to 59%), with side venting slightly more efficient due to a more optimal vent size. Emerging tankless water heating systems improve the efficiency to 80% by reducing standby losses. These systems, however, have a high up-front capital cost.

- <u>Electric</u>
  Electric water heaters do not require venting and the majority of standard electric water tanks, which are in service today, have efficiencies in the range of 90%. The efficiency of the standard

electric water tank (270L) has improved over the years from 84% to 91%. Some available tanks have slightly higher efficiencies of 92%.

- Geothermal
  Geothermal systems can be used in hot water heating applications; however these systems typically operate as a supplement to a conventional hot water heating system. In these joint system applications, the geothermal space heating system is used (through a desuperheater) to pre-heat water. This is accomplished during the space heating or cooling process. Under these applications, the overall energy requirements for water heating purposes are lower than a typical stand alone conventional hot water tank. A geothermal assisted system combined with a Power Smart Gold electric tank can improve system efficiencies to approximately 115%.

The following tables provide estimated capital and operating costs for conventional electric and both conventional and side vented natural gas water heaters. The first table provides costs associated with replacing a water heater in an existing home at the end of its life, while the second table provides the costs associated with installing a water heater for the first time in a new home. For geothermal systems, the incremental capital cost of a desuperheater is added to the cost of a conventional electric water heater. The operating costs presented below are typical for an average residential home (i.e. 2.4 occupants per home) and are based on energy rates in effect on May 1, 2012 (natural gas rate of $0.2220 per cubic metre and electric rate of $0.0677 per kilowatt hour).

Water Heating: End-of-Life Replacement (Existing Homes)

	Annual Operating Costs	Cost to Purchase and Install Equipment (Includes Labour, Equipment & Material Costs)		
System Description		**Low**	**High**	**Average**
Electric Tank Type Water Heater (270 L)	$236	$800	$1,200	$1,000
Natural Gas Side Vent Tank Type Water Heater	$105	$1,500	$2,000	$1,750
Natural Gas Conventional (Natural Draft) Water Heater	$109	$800	$1,000	$900
Natural Gas Tankless Water Heater	$78	$3,000	$4,000	$3,500
Heat Pump Desuperheater and one 270 L electric preheat tank	$198	$1,700	$2,000	$1,850
Average incremental capital cost of choosing electric over natural gas side vent water heater				**($750)**
Average incremental capital cost of choosing electric over conventional natural gas water heater				**$100**
Average incremental capital cost of choosing heat pump desuperheater (with one electric tank) **over natural gas side vent water heater**				**$100**

Water Heating: New Construction

	Annual Operating Costs	Cost to Purchase and Install Equipment (Includes Labour, Equipment & Material Costs)		
System Description		**Low**	**High**	**Average**
Electric Tank Type Water Heater (270 L)	$236	$800	$1,200	$1,000
Natural Gas Side Vent Tank Type Water Heater	$105	$1,750	$2,250	$2,000
Natural Gas Tankless Water Heater	$78	$3,000	$4,000	$3,500
Heat Pump Desuperheater and one 270 L electric preheat tank	$198	$1,700	$2,000	$1,850
Average incremental capital cost of choosing electric over natural gas side vent water heater				**($1,000)**
Average incremental capital cost of choosing heat pump desuperheater (with one electric tank) **over natural gas side vent water heater**				**($150)**

Tankless and side-vent tank natural gas water heating systems offer the lowest operating cost, however the capital cost associated with these systems is much higher. Simple payback periods for tankless natural gas water heating systems range from 19 years, when compared to a conventional electric hot water tank, to 50 years compared to a natural gas side vent hot water tank. Provided a customer has a geothermal system for space heating, geothermal assisted systems offer the second lowest operating cost. Their incremental capital costs are up to approximately $100 to install the desuperheater and a conventional electric hot water tank, when compared to the natural gas side vent option. The desuperheater is supplemental equipment for a conventional geothermal space heating system. Electric hot water tanks have the highest operating cost with the lowest installation costs.

The new home market is virtually 100% transformed with electric water heaters being the equipment of choice for home builders. In retrofit and new construction applications, the capital cost of installing an electric hot water tank is less expensive than a natural gas side-vent water heater, primarily because of the additional cost associated with incremental piping and venting required for the side-vent natural gas water heating equipment. As a result, a natural gas side vent water heater is approximately $750 more than an electric water heater. In the retrofit market, where the existing venting is adequate, a conventional natural gas water heater is less costly to install than an electric water heater. However, in some retrofit applications where the furnace has been upgraded to a high efficiency model, the existing chimney may need to be sleeved or adjusted to adequately vent a conventional natural gas water heater; if required, this could increase installation costs by approximately $550, making the conventional natural gas water heater cost approximately $450 more than an electric water heater.

2.2 Residential Space/Water Heating Market Trends

For an average residential application, space and water heating represents approximately 70% of a customer's annual energy use.

For the purposes of this report, 'fuel switching' is defined as:

- 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;
- Customers (or homebuilders) building new homes who build where natural gas service is available, but instead choose to install electric heating equipment.

2.2.1 Space Heating

Currently, conventional electric, natural gas and geothermal space heating systems are used to meet 89% of the residential space heating requirements in individually metered homes in Manitoba. Approximately 11% is provided through other sources such as oil, propane and wood systems, or through traditional sources where a resident is not billed for heating (e.g. apartments where heat is provided through a common system). The following table provides the detailed breakdown of the various system applications for space heating in today's residential market and the forecast market composition to 2030/31[1].

[1] All forecasts presented are based upon Manitoba Hydro's 2011 Electric Load Forecast and 2011 Natural Gas Load Forecast.

Breakdown of Key Residential Space Heating Technologies in Manitoba by Fuel Type

2011 Load Forecasts				
Year	Natural Gas	Electric	Geothermal	Other
2011/12	52.9%	34.3%	1.8%	11.0%
2020/21	51.1%	36.6%	2.4%	9.8%
2030/31	49.8%	38.4%	3.0%	8.8%

The forecasted trend in the market is for a slight shift towards the use of conventional electric space heating and geothermal applications. The market share for natural gas customers is projected to drop by approximately 3% to 49.8% by 2030/31.

2.2.2 Water Heating

With water heating applications in Manitoba, there is a trend towards using electric water heaters rather than natural gas water heaters. The following table provides the existing and forecast breakdown of natural gas and electric water heating applications to 2030/31 across the Province.[2]

Breakdown of Residential Water Heating Technologies in Manitoba by Fuel Type

2011 Load Forecasts		
Year	Natural Gas	Electric
2011/12	45%	55%
2020/21	32%	68%
2030/31	22%	78%

The shift in fuel choice for water heating applications is significant, with natural gas water heating systems expected to drop to 22% of the total market by 2030/31. This shift in fuel choice is attributed primarily to capital cost considerations. This move toward electric water heating is taking place in both the replacement market (existing homes) and new construction market (new homes). Almost 100% of new homes being built will have electric water heaters.

The following table presents the market breakdown and forecast for natural gas heated homes. By 2030/31, over 59% of natural gas heated homes are expected to use electric water heaters. Currently, this market share is 25%.

[2] All forecasts presented are based upon Manitoba Hydro's 2011 Electric Load Forecast and 2011 Natural Gas Load Forecast.

Residential Water Heating

2011 Load Forecast	
Year	% of Gas Space Heat Customers Using Electric Water Heat
2011/12	25%
2020/21	45%
2030/31	59%

2.2.3 Factors Influencing Market Shifts in Fuel Choice

There are a number of factors influencing the market shift from using natural gas to electricity for space and water heating purposes including economic, environmental and marketing related issues. The following section discusses these driving factors in detail.

- **Higher Natural Gas Prices:** The commodity component of a customer's natural gas bill (Primary Gas) has experienced an increase from approximately $0.20/m³ in 2000 to a high of $0.33/m³ in 2008. Although prices have recently retracted substantially and long-term price projections show a sustainable commodity price in the $0.15-$0.19/m³ ($4-5/GJ)[3] range, many consumers still expect natural gas rates to increase or fluctuate in the future. With electricity, customers have experienced modest increases in rates for a number of years and generally expect future electricity prices to continue to be relatively stable.

  For the operating costs of using natural gas with a high efficient furnace to equal the operating costs of using electricity, the bundled natural gas rate would need to increase to the following levels:
  - $0.65/m³ excluding the basic monthly service charge for natural gas service (i.e. for customers who would choose to continue taking natural gas service for other end uses such as fireplaces or stoves); or
  - $0.55/m³ including the basic monthly service charge.

  This means Manitoba Hydro's primary natural gas rate would be in the range of $0.42 - $0.52/m³, assuming all other rate components and fees in effect as of May 1, 2012. This is equivalent to a commodity market price of $11-14/GJ which is considerably higher than today's market price forecasts.

- **Greater Natural Gas Price Volatility:** Prior to the past decade, the cost of natural gas remained fairly consistent within the $0.08-$0.11/m³ ($2-3/GJ) range, resulting in low, stable prices for natural gas consumers. Since 2000, natural gas market prices have experienced a considerable amount of volatility fluctuating from $0.08-$0.49/m³ ($2-13/GJ)[4]. As a result, general consumers' perception is that natural gas retail rates will continue to be volatile and result in considerable uncertainty associated with consumers' future energy costs and bills.

- **Climate Change:** Customers are becoming increasingly more aware and conscious of climate change issues. Locally, the use of natural gas has generally shifted toward a negative perception

[3] http://www.hydro.mb.ca/regulatory_affairs/energy_rates/natural_gas/centra_pricing_chart.pdf (Monthly Alberta Firm Index and Futures Price at AECO)
[4] http://www.nrcan.gc.ca/eneene/sources/natnat/hishis-eng.php (AECO Price from November 2000 forward.)

as the electricity generated within Manitoba is predominately renewable and from clean hydraulic generation.

- **Capital Cost:** Electric water heaters can have a slightly higher capital cost relative to conventional natural gas water heaters. When compared to side-vent natural gas water heaters, however, electric water heaters are less expensive. The cost of side-vent natural gas water heaters has increased over the past decade at a faster rate than electric water heaters. In some retrofit applications where the natural gas furnace has been upgraded to high efficiency, the existing chimney may need to be sleeved or adjusted to adequately vent a conventional natural gas water heater; if required, this will increase the cost of the furnace installation. In some situations, contractors may encourage these customers to also install an electric water heater rather than assessing the need for adjusting the venting or installing a more costly side-venting natural gas water heater which will eliminate the need for a chimney. The capital cost gap, combined with the narrowing of operating costs (real and perceived) associated with the two fuel choice options, has resulted in contractors and homeowners being more inclined to install electric water heaters.

3.0 EVALUATION ASSUMPTIONS

The impacts of using electricity versus natural gas for space and water heating purposes is assessed from a load, economic and environmental perspective. The assumptions used in the assessments are outlined in the following sections.

||| 3.1 Load Impact Assumptions

The energy consumption for residential space heating is calculated for an average home of approximately 1,200 square feet. Actual consumption for specific homes will vary due to a range of factors, including weather, type of heating equipment, size, insulation levels, air tightness and lifestyle. For the water heating impacts, the energy consumption provided is based on the typical usage of the average Manitoba household with 2.4 occupants living in the residence.

The following table provides the energy use assumptions used for the various residential space and water heating options.

Function	Heating Fuel	System Details	Seasonal Efficiency / Energy Factor	Energy Units consumed/year
Space Heating	Natural Gas	High-Efficiency Forced Air	92%	1,776 m^3
	Geothermal	Forced Air/Hydronic SCOP = 2.5	250%	6,556 kWh
	Electricity	Forced Air Furnace/ Baseboard	100%	16,391 kWh
Water Heating	Natural Gas	Conventional	57%	491 m^3
	Geothermal	Combined w/ PS Gold Tank	99%	2,925 kWh
	Electricity	40 gallon	83%	3,489 kWh

Recognizing the potential installed performance ranges of geothermal heat pump systems, a sensitivity analysis outlining the impacts of achieving an SCOP of 3.5 is presented in Section 5.1.

||| 3.2 Economic Impact Assumptions

The economic impact is assessed from the customer, utility and provincial perspective. Generic assumptions include:

- A discount rate of 6.1% for all present value calculations.
- Electricity and natural gas rates are based upon Manitoba Hydro's 2012 electricity and natural gas price forecasts. The electric rates are adjusted to include the interim approved rate increase of 2.0% effective April 1, 2012.
- Electricity and natural gas marginal benefits are based upon Manitoba Hydro's 2012 Marginal Benefits Forecast.
- For per household impacts, the net present value is calculated over the life of the equipment (25 years for space heating and 10 years for water heating).

- For impacts included within the 2011 Load Forecast, the present value analysis is undertaken over a 30 year forecast period.
- The forecast period includes 2011 to 2040 with customer and appliance forecasts based upon the 2011 Manitoba Hydro Load Forecasts.

3.2.1 Customer Perspective:

To assess the economic impact of fuel choice options for space and water heating applications from the customer's perspective, the following formula was used:

Customer Perspective	=	PV (Customer Natural Gas Bill Reductions) - PV (Customer Electricity Bill Increases) - PV (Capital Cost Differences)

In the context of switching from natural gas to electricity:

- PV (Customer Natural Gas Bill Reductions) - refers to the present value of the reduced cost arising from decreased natural gas consumption due to a customer choosing to use electricity rather than natural gas. For the purposes of the analysis, it will be assumed that a customer no longer has natural gas service when using alternative fuels for space heating. Under this circumstance the customer would not pay a natural gas basic monthly charge.
- PV (Customer Electricity Bill Increases) - refers to the present value of the additional cost from increased electricity consumption due to a customer choosing electricity over natural gas.
- PV (Capital Cost Differences) - includes the total incremental costs associated with a particular heating system and the difference in installation costs between the natural gas technology and the electric/geothermal technology installed.
- Assumptions regarding capital and operating costs are provided in Section 2.0.

3.2.2 Utility Perspective:

The economic impact to the utility, with respect to an electric and natural gas perspective, was examined separately. The analyses on fuel choice options for space and water heating applications were based upon the following formulas:

Utility Perspective $_{electricity}$	=	PV (Customer Electricity Bill Increases) - PV (Electric Marginal Costs)

Where:

- PV (Customer Electricity Bill Increases) - refers to the net present value of additional revenue from increased domestic electricity consumption due to customers using electricity rather than natural gas.

- PV (Electric Marginal Costs) - includes reduced export power revenue from increased domestic use and the cost of new infrastructure advancement (e.g. electric transmission and distribution facilities).

$$\text{Utility Perspective}_{\text{natural gas}} = \text{PV (Natural Gas Marginal Benefits)} - \text{PV (Customer Natural Gas Bill Reductions)}$$

Where:

- PV (Natural Gas Marginal Benefits) - includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs. The value of reduced greenhouse gas emissions (GHGs) is not included in this analysis. At this time, there is no monetary value resulting from reduced greenhouse gas emissions under existing policies.
- PV (Customer Natural Gas Bill Reductions) refers to the present value of reduced revenue from decreased natural gas consumption due to customers using electricity rather than natural gas.

CONSIDERATIONS EXCLUDED FROM THE ABOVE ANALYSES:

The analysis provided within this report is intended to give a high level assessment of future economic impacts on Manitoba Hydro when customers choose to use electricity rather than natural gas for space and water heating applications.

It should be noted that the marginal benefits/costs utilized in this analysis are applicable for analyzing smaller, incremental energy impacts. The assessment does not include the economic impacts to Manitoba Hydro that would result from changes to the electricity load profile in Manitoba due to significant fuel shifting towards using electricity for space heating within natural gas serviced areas. For example in gas serviced areas, the electrical system is not designed to accommodate high electricity consumption increases. Major electrical distribution infrastructure upgrades would be required should such a shift occur (e.g. overhead and underground supply lines, transformers etc.). The impact on electrical distribution infrastructure is even greater in the scenario where a substantial number of customers shift to using geothermal technology.

3.2.3 Integrated Utility/Customer Perspective:

To assess the economic impact of fuel choice options for space and water heating applications from the perspective of the utility and the customer combined, the following formula was used.

$$\text{Integrated Utility/Customer Perspective} = \text{PV (Natural Gas Marginal Benefits)} - \text{PV (Electricity Marginal Costs)} - \text{PV (Capital Cost Differences)}$$

Where:

- PV (Natural Gas Marginal Benefits) - includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs. The value of reduced greenhouse gas emissions (GHGs) is not included in this analysis. At this time, there is no monetary value resulting from reduced greenhouse gas emissions under existing policies.
- PV (Electric Marginal Costs) - includes reduced export power revenue from increased domestic use and the cost of new infrastructure advancement (e.g. electric transmission and distribution facilities).
- PV (Capital Cost Differences) - includes the total incremental costs associated with a particular heating system and the difference in installation costs between the natural gas technology and the electric/geothermal technology installed.

3.2.4 Provincial Perspective (Inflow/Leakage):

Provincial Inflow/Leakage refers to the change in dollars flowing into and out of Manitoba due to the impact of using electricity rather than natural gas for space and water heating applications, the following formula was used.

Provincial Inflow/Leakage Impact	=	NPV of changes in dollars flowing into and out of the Province

- Includes the avoided cost of purchasing and transporting natural gas to the Manitoba border.
- Includes the lost revenue from reduced export electricity sales.

||| 3.3 Environmental (GHG) Impact Assumptions

The environmental (GHG) impact of using alternate fuel sources is quantified by the change in the amount of GHG emissions produced when using each type of fuel. The measure of GHG emissions are stated in CO_2e (equivalent), which includes carbon dioxide (CO_2) and the other major GHG emissions including, methane (CH_4) and nitrous oxide (N_2O).

The source of GHG emissions are characterized as being either direct or indirect as follows:

- **Direct Emissions** – These are the combustion emissions that would be created by consuming a fuel for a specific purpose in Manitoba (e.g. operating space or water heating equipment). The base emissions factor for natural gas (1.9 kg CO_2e /m^3) is a standardized factor utilized globally in the calculation of GHG emissions. In Canada, this emissions factor is utilized by Environment Canada in their GHG inventory assessments.[5]

- **Indirect Emissions** – Indirect emissions capture the secondary impact of changing electricity use in Manitoba and take into account the impacts of increased or decreased electricity exports.

[5] http://www.ec.gc.ca/pdb/ghg/ghg_home_e.cfm

Manitoba Hydro's primary export market is the Midwest Independent System Operator (MISO) region. The marginal generation in MISO is fossil fuel based (primarily coal). The average of emission factors for additional units of generation needed or avoided due to changing Manitoba electricity exports has been conservatively estimated at approximately 750 kg CO_2e/MW.h. This estimate was devised under today's market conditions and existing policies and only includes the burner tip emissions from generation outside of Manitoba; it does not include other lifecycle considerations such as fuel extraction, processing and transportation.

Longer term impacts are more uncertain as the emission impacts will be directly influenced by potential greenhouse emission policy changes that may be implemented within the export market (e.g. a policy placing restriction or a cap on greenhouse gas emissions).

The chart below outlines the emission factors used within this analysis.

Heating Fuel GHG Intensity Factors (kg $C0_2e$ / kW.h)

Fuel Type	Direct End Use (Manitoba Emissions)	Indirect Displacement (US Emissions)
Natural Gas	0.1836	
Electricity		0.75

The table below compares the change in GHG emissions attributed to using each fuel source for space and water heating applications in an average residential home. The net GHG impacts in the U.S. are based on current policies.

Potential Annual GHG Impacts

(Attributed by Region due to Fuel Use by MB Residential Customer)

Function	Heating Fuel (Manitoba Residential Customer)	Manitoba (kg C02e / year)	Us - MISO Region (kg C02e / year)	Net Global Impact (kg C02e / year)
Space Heating	Natural Gas	3,374	---	3,374
	Geothermal SCOP 2.5	---	4,917	4,917
	Geothermal SCOP 3.5	---	3,512	3,512
	Electricity	---	12,293	12,293
Water Heating	Natural Gas (Side Vent)	901	---	901
	Natural Gas (Conventional)	933	---	933
	Geothermal	---	2,194	2,194
	Electricity	---	2,617	2,617

The Western Climate Initiative (WCI) projects carbon market abatement costs to reach $33/tonne CO_2e by 2020[6].

For comparison purposes, the following formula was used to assess the relative cost of the GHG impacts of converting from natural gas to electric heating:

$$\text{Levelized Cost per tonne GHG} = \frac{\text{PV (Integrated Utility/Customer Costs)}}{\text{PV (Annual kg } CO_2e \text{ GHG impacts) / (1000 kg/tonne)}}$$

Where:

- PV (Integrated Utility/Customer Costs) – represents the net costs from the perspective of the utility and the customer combined of converting from natural gas heating to electric as outlined in Section 3.2.3.
- PV (Annual kg CO_2e GHG impacts) – represents the annual GHG reduction realized by converting from natural gas heating to electric over the life of the heating equipment.

[6] http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/Updated-Economic-Analysis-of-the-WCI-Regional-Cap-and-Trade-Program/

4.0 Impacts of Fuel Switching in Manitoba

||| 4.1 Per Household Impacts

This section provides the impacts for an average residential household where a natural gas heating system is replaced with either an electric or geothermal system for space and water heating. Energy load, economic, provincial leakage and environmental impacts are assessed by presenting three different fuel switching scenarios:

1. Switching from a gas to an electric furnace;
2. Switching from a gas furnace to a geothermal system (assuming SCOP of 2.5); and
3. Switching from a conventional natural gas hot water tank to an electric hot water tank.

Recognizing the potential installed performance ranges of geothermal heat pump systems, a sensitivity analysis outlining the impacts of achieving an SCOP of 3.5 is presented in Section 5.1.

4.1.1 Energy Load Impact

The following table provides the annual electric and natural gas load impact associated with a typical residential household fuel switching from gas to electric.

Load Impact of Fuel Switching
Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Electric Load Impact (kW.h)	16,391	6,556	3,489
Natural Gas Load Impact (m^3)	(1,776)	(1,776)	(491)

4.1.2 Economic Impact

The following table provides the electric and natural gas economic impact associated with an average residential household using electricity as opposed to natural gas for space and water heating applications. The economic impact is a net present value assessment taken over the life of the equipment, and includes the incremental capital cost of choosing electric over natural gas equipment in addition to operating costs. Operating costs are based on forecasted natural gas and electricity rates. Maintenance costs are not included in the calculation.

Net Economic Impact of Fuel Switching (over the life of the equipment)
Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5*)	Conventional Gas to Electric Water Heat
Utility Perspective (Electric)	($3,223)	($1,563)	($10)
Utility Perspective (Natural Gas)	($4,107)	($4,107)	($317)
Customer Perspective - Remaining Natural Gas Service	($9,146)	($12,685)	($727)
Customer Perspective - No Remaining Natural Gas Service	($7,737)	($11,276)	n/a
Integrated Utility / Customer Perspective	($15,067)	($16,946)	($1,054)

**A sensitivity analysis outlining the impacts of using a geothermal system with SCOP of 3.5 is presented in section 5.0.*

Utility Perspective – Changing to an electric space heating or water heating system results in a negative economic impact from the utility's perspective for both electricity and natural gas operations.

From the electric perspective, customers would be using more electricity, resulting in increased domestic electric revenues. However, reduced export revenues and the cost of advancing new electric infrastructure would be higher than the additional revenue gained domestically, therefore resulting in an overall negative impact.

From the natural gas perspective, customers would be consuming less natural gas, thereby decreasing revenues to Manitoba Hydro. This loss outweighs the avoided costs of purchasing natural gas and transportation costs. Therefore, the net result is a negative impact to the utility.

Customer Perspective – Changing from a natural gas space or water heating system to an electric system results in a negative economic impact to a residential customer over the life of the system. It is important to note that in an existing home, choosing an electric water heater over a less costly conventional natural gas water heater results in a negative economic impact to the customer assuming no adjustments are required to the chimney ventilation. If adjustments to the chimney are required, installation costs could increase by approximately $550.

The analysis for the Customer Perspective - Remaining Natural Gas Service assumes that the customer maintains their gas service for other appliances in the home (e.g. fireplace, stove, BBQ). If the customer were to completely eliminate natural gas service to the home, they would also save the cost of the basic monthly charge. The NPV of the natural gas basic monthly charge over 25 years (i.e. the assessment period for space heating) is $2,257. As such, the negative impact of switching from natural gas to an electric furnace decreases for the customer, as outlined in the Customer Perspective – No Remaining Gas Service.

Integrated Utility/Customer Perspective – From a combined utility and customer perspective, changing to an electric space heating or water heating system in an average residential home results in an overall negative economic impact.

4.1.3 Provincial Inflow/Leakage Impact from Primary Energy Transactions

The following table provides an estimate of the net economic inflow/leakage that would result from typical residential household using electricity as opposed to natural gas for space and water heating applications. The following assessment considers changes to export electricity revenues that flow into Manitoba and changes to natural gas purchase costs that flow out of Manitoba, using a net present value analysis over the 25 year life of space heating equipment, and 10 year life of water heating equipment.

Provincial Inflow (Leakage) Over the Life of the Equipment

Revenue / Cost Stream	Gas to Conventional Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Lost Export Revenue	($12,331)	($4,999)	($1,247)
Avoided Gas Supply Costs	$6,060	$6,060	$950
Net Provincial Cash Inflow (Leakage)	($6,271)	$1,061	($297)

A net incremental provincial leakage over the life of space and water heating equipment results when electricity is used instead of natural gas. In the case of using a geothermal system relative to a natural gas heating system, there is a net inflow to the Province. However, a more complete analysis would need to account for the higher cost geothermal furnace units which are imported into Manitoba relative to the cost of importing natural gas furnaces/air conditioning units (note geothermal units are estimated to cost $2000 - $3000 more).

4.1.4 Environmental (GHG) Impact

The following table provides the annual GHG emission impacts associated with a typical residential customer choosing electricity as opposed to natural gas for space and water heating applications.

Potential Annual GHG Impacts

(Attributed by Region due to Energy Use)

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Manitoba (kg CO_2e / year)	(3,374)	(3,374)	(933)
US - MISO Region* (kg CO_2e / year)	0 to 12,293	0 to 4,917	0 to 2,617
Net Global* (kg CO_2e / year)	(3,374) to 8,919	(3,374) to 1,543	(933) to 1,684

** The US-MISO Region and Net Global impacts are shown within a range, which includes the impact under today's emission policies in export regions and potentially what the impacts would be under more aggressive emission policies in export regions*

As the table indicates, an average residential home choosing to use electricity instead of natural gas for space and water heating would result in lower annual GHG emissions in Manitoba.

Manitoba Hydro recognizes that the impact of fuel choices made within Manitoba has an indirect implication outside of Manitoba. Manitoba Hydro's primary export market, the MISO region of the U.S. Midwest, uses fossil fuel based generation (primarily coal) to generate electricity. Electricity exports from Manitoba currently displace emissions from fossil fuel generation in export regions. The marginal emission factors are estimated to be 750 kg CO2e/MW.h.

Based on this, the use of electricity as opposed to natural gas in Manitoba will decrease exports and increase annual emissions in these external markets by 12,293 kg/year (electric heat versus natural gas for space heating), 4,917 kg/year (geothermal versus natural gas for space heating) and 2,617 kg/year (electric hot water tanks versus natural gas).

In the longer term, the indirect emission reductions may diminish if future energy and environmental policies in export regions change. The US-MISO region and net global emission impacts are shown within a broad range which includes the impact under today's emission policies in export regions and potentially what the impact would be under more aggressive future emission policies in export regions. Under today's policies from a global perspective, the increasing movement from natural gas to electricity in Manitoba for space and water heating would increase net annual emissions by 8,919 kg/year if an electric furnace is installed, 1,543 kg/year if a geothermal system is installed and by 1,684 kg/year for an electric water heater.

The Western Climate Initiative (WCI) projects carbon market abatement costs to reach \$33/tonne CO_2e by 2020[7]. The following table demonstrates that the relative cost per tonne of CO_2e reduction in Manitoba achieved by converting from natural gas heating to electric heating is higher than the projected abatement costs.

Levelized Cost per Tonne GHG Reduction in Manitoba – Average Residential Home

Space Heating	
Convert Natural Gas Furnace to Electric Furnace	\$333
Convert Natural Gas Furnace to Geothermal Heat Pump with 2.5 SCOP	\$377
Water Heating	
Convert Conventional Natural Gas Water Heater to Electric Heater	\$154

4.2 2011 Energy Forecasts

The following section presents the projected impacts of customer fuel switching based upon Manitoba Hydro's 2011 energy forecasts. The following table summarizes the projections for the cumulative number of residential and commercial customers switching from natural gas to electric equipment in existing homes and buildings as well as customers installing electric equipment instead of natural gas equipment in new homes and buildings in natural gas serviced areas. The forecast of overall electric and natural gas customers is provided for comparison.

[7] http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/Updated-Economic-Analysis-of-the-WCI-Regional-Cap-and-Trade-Program/

Year	Cumulative # of Fuel Switched Customers				Total # of Customers (Meters)			
	Space Heating		Water Heating		Electric		Natural Gas	
	Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial
2020/21	23,511	440	72,868	440	502,547	71,267	261,356	25,405
2030/31	47,592	920	146,316	920	555,142	76,298	282,131	26,206

4.2.1. Energy Load Impact

The following table provides the impact on Manitoba Hydro's electric load relative to the 2011 Electric Load Forecast.

2011 Load Forecast (Net Firm Energy) 2030/31 (GW.h)	Portion of 2011 Forecast Attributed to Fuel Switching 2030/31		
		GW.h	% of Load
32,465	Space Heating:	605	2%
	Water Heating:	269	1%

From an incremental perspective, the 2011 forecast includes increased domestic electric load due to fuel switching of 874 GW.h by 2030/31, which represents 3% of the expected 2030/31 domestic electrical load.

The table below provides the impact of fuel switching on Manitoba Hydro's domestic natural gas load in 2030/31 (Total Gas Volume Forecast) which is included in the 2011 Natural Gas Volume Forecast.

2011 Load Forecast (Total Natural Gas Sales) 2030/31 (10^6m^3)	Portion of 2011 Forecast Attributed to Fuel Switching 2030/31		
		(10^6m^3)	% of Load
1,924	Space Heating:	(65)	-3%
	Water Heating:	(38)	-2%

The 2011 forecast includes a reduction in provincial natural gas sales of 5% in 2030/31. From an incremental perspective, the 2011 forecast includes decreased domestic sales of 103 million cubic metres by 2030/31.

4.2.2 Economic Impact

The net present value economic impact under the 2011 load forecasts over the next 30 years for space and water heating applications is outlined in the following table.

Net Economic Impact – 2011 Energy Forecasts

(Net present value over 30 year forecasting period)

Space Heating	$ millions
Utility Perspective (Electric)	($107)
Utility Perspective (Natural Gas)	($38)
Customer Perspective	($223)
Integrated Utility / Customer Perspective	($368)
Water Heating	
Utility Perspective (Electric)	($25)
Utility Perspective (Natural Gas)	($31)
Customer Perspective	($88)
Integrated Utility / Customer Perspective	($144)

Utility Perspective – Overall, the economic impact of the expected market change to Manitoba Hydro's electric business is negative by approximately $132 million, with changes in space heating and water heating negatively contributing $107 million and $25 million respectively. Manitoba Hydro's natural gas operations are also negatively impacted by approximately $69 million, with changes in space and water heating negatively contributing $38 million and $31 million respectively.

Customer Perspective - Installing electric space and water heating equipment in natural gas serviced areas results in a negative economic impact to customers overall of $223 million and $88 million respectively. This analysis assumes that both residential and commercial customers choose electric water heaters over conventional natural gas water heaters.

Integrated Utility/Customer Perspective - From a combined perspective, the scenario results in a negative overall economic impact of $512 million, with changes in space heating and water heating negatively contributing $368 million and $144 million respectively.

4.2.3 Provincial Inflow/Leakage Impact from Primary Energy Transactions

The following table provides the 2011 forecasted impact on the provincial economic inflow/leakage over the next 30 years that would result from reduced export power revenue net of reduced natural gas purchases.

Provincial Inflow (Leakage)

(Net present value over 30 year forecasting period)

Revenue / Cost Stream	2011 Forecast ($ millions)
Lost Export Revenue	($505)
Avoided Gas Supply Costs*	$251
Net Provincial Cash Inflow (Leakage)	**($254)**

The 2011 forecasted market change results in an estimated net provincial leakage of $254 million.

4.2.4 Environmental (GHG) Impact

The following table provides the environmental (GHG) impact of the 2011 forecasted market fuel switching in space and water heating.

Potential Annual GHG Impacts

(Attributed by Region due to Energy Use)

Year	Manitoba (tonnes C02e / year)	US - MISO Region* (tonnes C02e / year)	Net Global Impact* (tonnes C02e / year)
2012/13	(11,970)	38,753	26,783
2022/23	(154,166)	0 to 496,268	(154,166) to 342,102
2032/33	(203,699)	0 to 687,473	(203,699) to 483,774

** The US-MISO Region and Net Global impacts are shown within a range, which includes the impact under today's emission policies in export regions and potentially what the impacts would be under more aggressive emission policies in export regions.*

Under current emissions and energy policies, the net environmental (GHG) impact of the 2011 forecast results in reduced annual emissions in Manitoba and increased annual global emissions. Over the long term, the impact in the US-MISO region and the net global impacts will be dependent upon future emissions policies.

5.0 Sensitivity Analysis

5.1 Impact of Improved Performance in Geothermal Systems

As stated in section 2.1, most geothermal systems operate with a Seasonal Coefficient of Performance (SCOP) in the range of 2.0 – 3.0 (200-300% efficient) with some systems achieving SCOP as high as 3.5 depending on the quality and configuration of the system. The following analysis shows the load, economic and environmental impacts of a geothermal system performing at an improved performance level of SCOP 3.5 compared to the average geothermal system achieving an SCOP of 2.5 that is presented in the main analysis.

Net Impact of Fuel Switching to Geothermal (over 25 years)
Average Residential Home

	Gas to Geothermal (SCOP 2.5)	Gas to Geothermal (SCOP 3.5)
Annual Energy Load Impact		
Electric Load Impact (kW.h)	6,556	4,683
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)
Economic Impact (NPV over the life of the equipment*)		
Utility Perspective (Electric)	($1,563)	($1,117)
Utility Perspective (Natural Gas)	($4,107)	($4,107)
Customer Perspective - Remaining Natural Gas Service	($12,685)	($10,806)
Customer Perspective - No Remaining Natural Gas Service	($11,276)	($9,397)
Integrated Utility / Customer Perspective	($16,946)	($14,621)
Net Provincial Cash Inflow (Leakage)	$1,061	$2,489
Annual Environmental Impact		
Manitoba (kg CO_2e / year)	(3,374)	(3,374)
US - MISO Region (kg CO_2e / year)	0 to 4,917	0 to 3,512
Net Global (kg CO_2e / year)	(3,374) to 1,543	(3,374) to 138

Overall, the results are directionally the same. There is a negative impact to the utility and customer when switching from a gas furnace to a geothermal system (SCOP 3.5) and a net Provincial cash inflow. Compared to the geothermal SCOP 2.5, the negative impacts are less with a SCOP of 3.5 because the system is performing at a higher efficiency (i.e. using less electricity but displacing the same amount of natural gas).

5.2 Water Heating Technology Options

Installing a high efficiency natural gas furnace may require modification to the home's venting system. In order to avoid costly venting upgrades, customers often choose to install an electric hot water tank. However, another option is to install a natural gas water heater that vents out the side wall.

The following analysis demonstrates the impacts if a customer was switching from a side-vent natural gas tank to an electric hot water tank. The impacts of changing from a conventional natural gas tank are also shown as a basis for comparison.

Net Impact of Fuel Switching to Electric Water Heating (over 10 years)
Average Residential Home

	Conventional Gas to Electric Water Heat	Side-Vent Gas to Electric Water Heat
Annual Energy Load Impact		
Electric Load Impact (kW.h)	3,489	3,489
Natural Gas Load Impact (cu.m)	(491)	(474)
Economic Impact (NPV over the life of the equipment*)		
Utility Perspective (Electric)	($10)	($10)
Utility Perspective (Natural Gas)	($317)	($306)
Customer Perspective - Remaining Natural Gas Service	($727)	$176
Customer Perspective - No Remaining Natural Gas Service	n/a	n/a
Integrated Utility / Customer Perspective	($1,054)	($140)
Net Provincial Cash Inflow (Leakage)	($297)	($330)
Annual Environmental Impact		
Manitoba (kg CO_2e / year)	(933)	(901)
US - MISO Region (kg CO_2e / year)	0 to 2,617	0 to 2,617
Net Global (kg CO_2e / year)	(933) to 1,684	(901) to 1,716

Compared to a conventional gas hot water tank, a side-vent gas tank is only marginally more efficient (474 cu.m per year vs 491 cu.m per year). Therefore the impact to the utility is similar for both technologies. The notable difference is within the Customer Perspective which results in a net benefit of $176 to the customer when choosing between a side-vent natural gas and an electric hot water tank. Customers are better positioned economically when using electricity for water heating due to the high upfront capital cost of the side-vent natural gas tank (which the customer would be saving if they switched to electric). This is common in new home construction where chimneys are no longer required for venting high efficiency natural gas furnaces, thereby limiting natural gas water heater options to the higher capital cost side-vent options. In the retrofit market where the existing venting is adequate, the customer is better positioned economically using natural gas for water heating if choosing a conventional natural gas water heater.

5.3 Impact of Increased Primary Natural Gas Prices

As stated in Section 3.2, the economic impacts presented with this report are based upon Manitoba Hydro's 2012 natural gas price forecast. Recognizing the influence of natural gas prices on consumers' fuel choices, the following sensitivity explores the economic impact of using electricity instead of natural gas for space and water heating in an environment of high primary natural gas prices. The following analysis provides the economic impact from the customer's and utility's perspective along with a high level assessment of provincial leakage assuming primary natural gas prices remain at $0.33/cu.m over the forecast period, the highest recorded level as observed in August 2008.

5.3.1 Economic Impact

The following table provides the electric and natural gas economic impact associated with an average residential household using electricity as opposed to natural gas for space and water heating applications under increased primary natural gas prices.

Net Financial Impact of Fuel Switching (over the life of the equipment)
Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Utility Perspective (Electric)	($3,223)	($1,563)	($10)
Utility Perspective (Natural Gas)	($4,107)	($4,107)	($317)
Customer Perspective - Remaining Natural Gas Service	($6,697)	($10,236)	($285)
Customer Perspective - No Remaining Natural Gas Service	($4,440)	($7,979)	n/a
Integrated Utility / Customer Perspective	**($11,770)**	**($13,649)**	**($612)**

Utility Perspective – Increases to the primary natural gas component of Manitoba Hydro's rates do not affect the economic impact to the utility of changing to an electric space heating system as primary natural gas is a flow-through cost to the customer.

Customer Perspective – Under increased primary natural gas prices, changing from a natural gas space heating system to an electric or geothermal system continues to result in a negative economic impact to the customer. In addition, a conventional natural gas water heater remains more economic to the customer than an electric water heater under 2008 primary natural gas prices.

5.3.2 Provincial Inflow/Leakage Impact from Primary Energy Transactions

The following table provides an estimate of the net economic inflow/leakage that would result from typical residential household using electricity as opposed to natural gas for space and water heating applications under increased primary natural gas prices.

Provincial Inflow (Leakage) Over the Life of the Equipment

Revenue / Cost Stream	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Lost Export Revenue	($12,331)	($4,999)	($1,247)
Avoided Gas Supply Costs	$8,509	$8,509	$1,393
Net Provincial Cash Inflow (Leakage)	($3,822)	$3,510	$146

Assuming 2008 primary natural gas prices, changing from a natural gas space heating system to a conventional electric system continues to result in a lower net incremental provincial leakage over the life of the equipment. However, with increased natural gas prices, using electricity for water heating shifts to become a net incremental provincial inflow.

In the case of using a geothermal system relative to a natural gas heating system, the net inflow to the Province increases if primary natural gas prices increased to that observed in 2008.

5.4 Hypothetical Potential Analysis – Impacts of Total Conversion

The following analysis provides insight into the hypothetical load impacts if all customers in Manitoba replaced their existing space and water heating equipment with an alternative natural gas, electric or geothermal system.

The following table presents:

- the existing annual electricity and natural gas load for space and water heating; and
- the hypothetical potential annual electricity and natural gas loads under extreme fuel conversion scenarios (i.e. immediate fuel switching to either all natural gas use, all electric use or all geothermal use for space and water heating purposes).

Hypothetical Annual Load Impact
If All Customers in Manitoba Immediately Switched to One Type of Heating Fuel

	Natural Gas (1000 m3)	Electricity (GW.h)	Geothermal SCOP 2.5 (GW.h)
Current load situation - space heat	938,723	3,473	67
Current load situation - water heat	194,925	1,097	0
A. Immediate fuel switch to natural gas - space	1,339,429	---	---
A. Immediate fuel switch to natural gas - water	349,251	---	---
B. Immediate fuel switch to electric - space	---	11,341	67
B. Immediate fuel switch to electric - water	---	2,482	---
C. Immediate switch to geothermal - space	---	---	4,603
C. Immediate switch to geothermal - water	---	---	2,081

Impacts are based on the electric and natural gas forecast for 2011.

47

From the electric utility perspective, the magnitude of the hypothetical potential impact of all customers switching to electric space and water heating would add 7,868 GWh and 1,385 GWh. respectively of annual electric load in Manitoba. Combined, this additional electric load would be equivalent to approximately two generating stations the size of Conawapa. Furthermore, it is important to recognize that the implications to the utility go beyond the analysis provided within this report. The consequence of a wholesale fuel switching scenario would also require a significant investment in additional generation, transmission and distribution infrastructure. In addition, the utility would be confronted with managing a more diverse winter/summer load. From the natural gas utility perspective, the remaining annual natural gas load would be 40% of the existing load and as such, the scenario would require a rate increase to the remaining natural gas customers to cover fixed costs (i.e. the fixed costs would need to be recovered from a much smaller customer base).

It should be noted that the hypothetical potential impact of all customers switching to natural gas space and water heating cannot be supported with today's natural gas infrastructure. The implications of this hypothetical scenario would also require extensive new infrastructure at an extraordinarily high cost.

6.0 A Review of Other Jurisdictions

Discussions with counterparts in BC Hydro, SaskPower, Ontario Power Authority and Quebec Hydro indicated their practices are consistent with Manitoba Hydro's current approach, which involves taking steps to educate consumers to assist them in making an informed decision. On the other hand, Canadian natural gas companies tend to promote natural gas for all uses; for example, some Canadian natural gas utilities, including Fortis BC and Gaz Metro, currently offer rebates to encourage the installation of natural gas home heating systems or water heating systems. The rebates are aimed at increasing market share for these natural gas utilities. A general review of US utilities found two integrated electric and natural gas companies promoting the use of natural gas for space and water heating. The following table outlines the incentives offered by utilities to support conversion to natural gas equipment.

Natural Gas Utility	Incentive per Conversion			Note
	Space Heating	Water Heating	Other Equipment/ Appliances	
Fortis BC	$1,000	n/a	n/a	Only conversions from oil/propane to natural gas eligible. Also offer high efficiency equipment rebates.
Gaz Metro (Quebec)	$900 - $1,100	$300 - $550	n/a	Also offer high efficiency equipment rebates.
Efficiency Nova Scotia Corporation	$500 for gas furnace $2,250 for gas boiler	$500 - $750	n/a	Additional incentive for 100% of the costs to remove electric baseboards and install new distribution system, up to a maximum of $3,000.
Puget Sound Energy – Electric & Natural Gas (Washington State)	$500 - $2,500	$950	n/a	$1,950 - $3,950 for both home heating and water heating combined Also offer high efficiency equipment rebates.
Avista Energy – Electric & Natural Gas (Washington State)	$750	$250	n/a	$750 is for conversion of conventional electric heating to natural gas or central heat pump Also offer high efficiency equipment rebates.

7.0 Future Considerations - Proposed Federal Regulations

Natural Resources Canada (NRCan) is proposing higher efficiency requirements for natural gas water heaters used in both residential and commercial applications and, in June 2010, began formal industry and stakeholder consultations. These changes, if adopted, will likely have a further impact on customer's fuel choices for water heating.

NRCan is proposing a minimum efficiency factor (EF) of 0.67 for residential natural gas water heaters effective April 1, 2016, and a minimum EF of 0.80 effective January 1, 2020. This regulation is aggressive, considering most residential water heaters currently available on the market have an EF between 0.57 and 0.60.

Residential customers replacing their water heater pay an average of $1,000 for an electric water heater while a standard natural gas side vented water heater with an EF of 0.59 costs $1,750. A preliminary market review indicates that water heaters with an EF of 0.67 can cost approximately $800 more than a side vent natural gas hot water tank, and few are currently available within the Manitoba market. In addition, the only water heaters currently available in Manitoba that offer an EF of 0.80 are condensing natural gas water heaters which can cost up to an additional $3,000 compared to a side vent natural gas water tank.

At current Manitoba energy rates, the incremental cost of natural gas water heaters (first time or conversion costs) under the proposed regulations will not be recovered through reduced operating costs over the life of the water heater. The large incremental product costs and limited availability of qualifying water heaters are anticipated to further accelerate the market conversion to electric water heating in the residential and commercial sector.

In addition to the above proposed regulations, NRCan is proposing a minimum Thermal Efficiency (TE) of 80% (effective date to be announced) and 92% effective January 1, 2018 for larger water heaters (greater than 75,000 btu/h input), which are typically used by commercial customers. The majority of commercial grade water heaters sold today in Manitoba have a TE of 80% and will meet the standard. Water heaters with a minimum TE of 92% have a higher initial cost but are less costly to operate versus an electric water heater; especially for heavy hot water users. Due to higher operating costs for electric water heaters, it is anticipated that these proposed changes will not materially influence heating fuel choices for high use commercial customers. They could however, have an impact on the fuel choice of customers with low to medium hot water usage, such as offices, warehouses and non-food retail buildings.

50

8.0 Conclusions

The following table summarizes the impact of using electricity instead of natural gas for space and water heating in a typical residential home. The economic impact to the customer includes the incremental cost of installing electric instead of natural gas heating equipment in new homes and existing homes. The economic impact is taken over the life of the equipment[8], whereas energy and environmental (GHG) impacts are shown on an annual basis.

Impact of Fuel Switching
Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5)	Conventional Gas to Electric Water Heat
Annual Energy Load Impact			
Electric Load Impact (kW.h)	16,391	6,556	3,489
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)	(491)
Economic Impact (NPV over the life of the equipment)			
Utility Perspective (Electric)	($3,223)	($1,563)	($10)
Utility Perspective (Natural Gas)	($4,107)	($4,107)	($317)
Customer Perspective - Remaining Natural Gas Service	($9,146)	($12,685)	($727)
Customer Perspective - No Remaining Natural Gas Service	($7,737)	($11,276)	n/a
Integrated Utility / Customer Perspective	($15,067)	($16,946)	($1,054)
Net Provincial Cash Inflow (Leakage)	($6,271)	$1,061*	($297)
Annual Environmental Impact			
Manitoba (kg CO_2e / year)	(3,374)	(3,374)	(933)
US - MISO Region** (kg CO_2e / year)	0 to 12,293	0 to 4,917	0 to 2,617
Net Global** (kg CO_2e / year)	(3,374) to 8,919	(3,374) to 1,543	(933) to 1,684

**The provincial inflow benefits will be offset by higher cost of geothermal units relative to the cost of natural gas furnaces and air conditioners (i.e. estimated at $2,000 to $3,000).*
***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

Overall, from the customer, utility, provincial leakage and global environmental perspectives, there are substantial benefits when customers use natural gas for space heating purposes. The directional impact for each of these factors is the same for using natural gas for space heating relative to using geothermal systems, except when considering provincial leakage impacts; however in the latter case, a more complete analysis would need to account for the higher cost geothermal furnace units which are imported into Manitoba relative to the cost of importing natural gas furnaces/air conditioning units (note geothermal units are estimated to cost $2000 - $3000 more). For water heating, the directional impact is the same as space heating. As a cautionary note, it should be recognized that this analysis is

[8] Space heating equipment is assumed to have a 25 year life, whereas water heating equipment is assumed to have a 10 year life.

using average cost estimates. Capital costs (i.e. quoted installation prices) can vary greatly in the market place and actual customer specific situations will vary considerably.

Electric Business Perspective
Manitoba Hydro's electric operations are better positioned economically when a consumer uses natural gas for space and water heating purposes as the utility's marginal costs (export revenues and avoided infrastructure costs) are higher than the domestic revenue realized through the sale of electricity in Manitoba. The value to the Corporation is $3,223 for each conventional space heating application, $1,563 for each geothermal application and $10 for each water heating application.

Natural Gas Business Perspective
Manitoba Hydro's gas operations are better positioned economically when a consumer uses natural gas for space and water heating purposes as the utility collects additional revenue from its customers through its fixed charges and distribution charges (assuming rates for these services remain unchanged). Primary Gas costs are a "pass through" cost and therefore, have no impact on the natural gas business. For this analysis, transportation costs are also considered a "pass through" cost as it is assumed that Manitoba Hydro could avoid these costs if customers reduced their use of natural gas. The value to the Corporation is $4,107 for each space heating system and $317 for each water heating system over the life of the equipment.

Customer Perspective
Caution must be exercised in reviewing the analysis from a customer's perspective due to the wide range of installation costs charged by industry for installing space and water heating systems. In addition, this analysis is for first time or conversion costs associated with installing a natural gas water heater.

For the purpose of this analysis and based on average costs, a customer is:

- $7,737 better off by installing a natural gas space heating system relative to a conventional electric furnace;
- $11,276 better off by installing a natural gas space heating system relative to a geothermal system achieving an average SCOP of 2.5; and
- $727 better off by installing a conventional natural gas water heater relative to an electric water heater.

Provincial Leakage
Over the life of the equipment, net provincial cash inflows are reduced by $6,271 and $297 respectively, when electric systems are used for space and water heating as compared to using a natural gas furnace or conventional gas hot water tank. Relative to using natural gas, using geothermal systems for space heating increases provincial cash inflows by $1,061 over 25 years.

Environmental (GHG) Impacts
Relative to using natural gas, using electricity for space and water heating in Manitoba will reduce provincial GHG emissions. Impacts on global GHG emissions, however, are less certain. In the short term, and potentially in the longer term, global GHG emissions will be increased due to reduced electricity exports from Manitoba under existing environmental policies. Manitoba's electricity exports replace fossil generation in export regions, thereby reducing more global GHG emissions than could be reduced provincially through less natural gas use. In the longer term, however, global impacts are less certain

and will depend on environmental policies at the time. For example, fewer electricity exports from Manitoba would not necessarily result in an increase to GHG emissions in an export region that imposed a GHG emissions cap. With lower electricity exports from Manitoba, the export region may need to take alternative action to ensure that emissions do not exceed an established cap. Manitoba's electricity may be just one of a number of other possible options for meeting that cap.

Market Trends
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. 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.

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.

Discussion
The potential impacts of fuel switching in Manitoba for space and water heating can be significant and the Corporation is monitoring market trends very closely. Given the economic drivers from a customer's perspective, it is unlikely that the Manitoba market will experience any overwhelming shift in space heating from natural gas to electricity, provided customers are informed on their choices. With water heating, the drivers are substantial enough that Manitoba Hydro expects to see a continued market shift from natural gas to electricity.

Manitoba Hydro recognizes the value customers place on having choice and the Corporation does not intend on mandating a specific fuel be used for space and water heating. Where appropriate, the Corporation prefers to use market intervention mechanisms (e.g. education, direct financial incentives, rate design options, etc.) to influence the market.

TAB 7

REFERENCE: Chapter 8: Determination and Description of Development Plans; Recent PRP(s)

QUESTION:

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.

RESPONSE:

Manitoba Hydro is unable to provide wind farm specific production information as it is commercially sensitive and confidential. Therefore any wind generation data prior to April, 2011, when only one wind farm was in production, has not been provided.

Total wind generation data for both St Leon and St Joseph since April, 2011 is as follows:

Year	MWh
2011/12	908267
2012/13	851139

Additional Manitoba wind development is considered as an energy resource option as described in Chapter 8 of the submission. However in order to ensure that load can be met, wind resources must be combined with firm capacity resources over time such as natural gas-fired generation in order that Manitoba Hydro can meet the capacity needs of customers in Manitoba.

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) 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, it would be uneconomic for Manitoba Hydro to develop additional wind energy in Manitoba for export purposes.

TAB 8

REFERENCE: Technical Conference, September 5, 2013; PowerPoint

QUESTION:

Please provide details as to the gas initiative and how Manitoba Hydro intends to advertise or promote gas.

RESPONSE:

Manitoba Hydro's current strategy is not to promote natural gas over electricity. 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. Total lifetime cost takes into consideration the cost to purchase, install and operate the heating system over its useful life. Messaging is communicated through a number of channels, including:

- energy bill inserts,
- newspaper advertisements in rural newspapers in gas available areas and in Winnipeg,
- magazine advertisements in local new home and renovation magazines, and

- brochures available throughout the natural gas available areas of Manitoba.

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 on 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. Other components of the educational effort introduced in 2013 include:

- targeted addressed mailings to customers with inactive natural gas services and low natural gas consumption,
- targeted unaddressed mailings to customers in natural gas available areas,
- online advertising, and
- enhancements to Corporate "Heating" webpage including the introduction of a heating cost comparison calculator and a heating system education video.

Advertising targeting new home buyers will continue to be placed in media serving natural gas available areas where there has been a high proportion of new homes being constructed with electric heating systems. Replacement system advertisements will continue to run throughout all natural gas available areas.

Manitoba Hydro's Heating Education Campaign also promotes financing options available through Manitoba Hydro which can assist customers with implementing alternative heating options. Manitoba Hydro offers a number of convenient on-bill financing services including the Power Smart Residential Loan, the Power Smart PAYS Financing Program and the Earth Power Loan Program. In many circumstances the customer's average monthly energy bill savings from

choosing a natural gas system over an electric system will offset the monthly finance fee. Educational materials speak to the availability and benefits of these convenient financing services.

To further assist customers with making fuel choice decisions, the Corporation provides technical expertise and guidance when appropriate and required. For example, during 2012 and 2013, staff performed energy assessments for 26 Hutterite colonies affected by the impending coal ban on heating. The energy assessments included an economic comparison of alternative energy choice approaches based on biomass, natural gas, geothermal, electric, propane and coal.

Manitoba Hydro's plans include ongoing monitoring of the market and assessing alternative or complementary demand side management strategies (e.g. service extension policies and incentive based programming).

TAB 9

2099

out to be a temporary end to the subsidy. It has ended once more. We don't yet know whether that's a temporary or a permanent end to the subsidy.

MR. WILLIAM GANGE: Thank you, sir.

A third hurdle is that although wind energy from Manitoba may technically qualify for meeting US renewable portfolio standards in some jurisdictions, Manitoba Hydro's US customers are not interested in purchasing wind energy from Manitoba to meet state renewable portfolio standards.

Is that correct, Mr. Cormie?

MR. DAVID CORMIE: Mr. Gange, that was the response that we gave to PUB Round 126A --

MR. WILLIAM GANGE: That's correct.

MR. DAVID CORMIE: -- and subsequently we've revised that to say that that -- it was in -- in error, and -- and I'm not sure why we -- we withdrew that as a barrier. I'll have to find out the reason why, but we don't consider that as a barrier anymore.

MR. WILLIAM GANGE: Okay. That -- that's helpful to me. Thank you. Appreciate that.

MR. DAVID CORMIE: However, wind from our -- our wind projects in Manitoba does not qualify under US renewable portfolio stands -- standards as a Class 1 RECs because the generation is external to the

2100

US. The only markets that have -- that -- that recognize -- that -- the only markets that have Class 1 RECs are PJM in the NEPOOL market. And Manitoba Hydro sells into MISO, and there is no Class 1 RECs recognized there.

MR. WILLIAM GANGE: From -- from listening to Mr. Swanson again this morning, my understanding was that -- that the -- Manitoba -- or -- or electricity generated in Manitoba pursuant to renewable standards would be permissible in the United -- would -- would be admitted into the United States as opposed to, I put to him, the coal generation scenario. And he -- and -- and my understanding was that his answer was, No, that would not be allowed into the United States.

Would -- am I accurately capturing his testimony there, the way that you heard it?

MR. DAVID CORMIE: Could -- could you repeat that again?

MR. WILLIAM GANGE: I asked Mr. Swanson if coal-generated power from Manitoba would be -- would be permissible in the United Sta -- would -- in -- in Minnesota. And I thought -- I'm pretty sure that his answer was, No, the -- the legislature -- the legislation would not allow it.

2101

That's correct, sir? That's what you heard?

MR. DAVID CORMIE: Yes, that's what he said, yes.

MR. WILLIAM GANGE: And my understanding was that -- that if it was coming from a renewable source then it would be permissible under that baseline component of the legislation. Did you understand that from his evidence?

MR. DAVID CORMIE: That to the extent that a US company purchased wind energy in Manitoba and received credit for that, they could use that to meet their RPS standard. Is that what you're saying?

MR. WILLIAM GANGE: No, what I was referring to was that he said that there is a ban on addition of baseload energy from fossil fuels. That's --

MR. DAVID CORMIE: Yes.

MR. WILLIAM GANGE: -- what I'm referring --

MR. DAVID CORMIE: Yes.

MR. WILLIAM GANGE: -- to.

MR. DAVID CORMIE: Yeah, I -- I agree with that.

MR. WILLIAM GANGE: And -- and -- but

2102

that energy coming into the United -- to -- to Minnesota could add to the baseline standard if it was renewable.

(BRIEF PAUSE)

DR. DEAN MURPHY: This is Dr. Murphy. I'll attempt a response, and I apologize because I haven't previously considered imports from Manitoba into the mid west. My studies have been mostly looking just at the mid west.

But my understanding this morning, the testimony was that the Minnesota statute which prohibits fossil energy would not prevent the import of renewable energy. I am not sure whether that renewable energy, if imported, would be counted towards the State's RPS.

MR. WILLIAM GANGE: Yes, and I'm not going so far as to go to the RPS. I'm just saying, Is it allowed in? And -- and the answer seems to be, Yes.

DR. DEAN MURPHY: That was the testimony that I heard this morning.

MR. WILLIAM GANGE: Yes. Okay. Thank you.

MR. DAVE CORMIE: And -- and to

TAB 10

Chapter PSC 118

RENEWABLE RESOURCE CREDIT TRACKING PROGRAM

Note: Chapter PSC 118 was created as an emergency rule effective April 7, 2001.

PSC 118.01 Scope. (1) This chapter applies to each Wisconsin electric provider that is subject to s. 196.378 (2) (a), Stats.

(2) The commission may consider exceptional or unusual situations and may, by order, apply different requirements to an individual facility than those provided in this chapter.

History: CR 00-065: cr. Register July 2001, No. 547 eff. 8-1-00; CR 06-112: am. Register May 2007 No. 617, eff. 6-1-07; CR 10-147: renum. 118.01 to be 118.01 (1) and am., cr. (2) Register March 2012 No. 675, eff. 4-1-12.

PSC 118.02 Definitions. The definitions specified in s. 196.378, Stats., apply to this chapter. In addition, in this chapter:

(1e) "Biogas" means a gas created by the anaerobic digestion or fermentation of biomass, food processing waste or discarded food.

(1m) "Certified non-electric facility" means a non-electric facility that the commission certifies under s. PSC 118.055.

(1s) "Certified renewable facility" means an electric generating facility that the commission certifies under s. PSC 118.05.

(2) "Compliance period" means a calendar year, beginning January 1, during which an electric provider is required to achieve a renewable energy percentage under s. 196.378 (2) (a), Stats.

(3) "Commission" means the public service commission.

(3m) "Densified fuel pellets" means pellets made from waste material that does not include garbage, as defined in s. 289.01 (9), Stats., and that contains no more than 30 percent fixed carbon.

(4) "Designated representative" means the person authorized by the electric provider to register a renewable facility or non-electric facility with the program administrator, or to purchase or sell renewable energy certificates or RRCs.

(5) "Displaced conventional electricity" means electricity derived from conventional resources that an electric provider, or a customer or member of the electric provider, would have used except that the person used instead a certified non-electric facility.

(5m) "Division administrator" means the administrator of the commission's division responsible for energy regulation.

(6) "MWh" means megawatt-hour of electricity.

(6g) "Non-electric facility" means any of the following when used by an electric provider, or by a customer or member of the electric provider:

(a) A solar water heater.

(b) A solar light pipe.

(c) A ground source heat pump.

(d) An installation generating thermal output from biomass, biogas, synthetic gas, densified fuel pellets, or fuel produced by pyrolysis.

(e) Any other installation under s. 196.378 (3) (a) 1m., Stats., identified by the commission that meets the criteria specified in this chapter.

(6r) "Plasma gasification" means the process of using an electric arc gasifier at a high temperature to break down waste material into gases and solids.

(7) "Program administrator" means the person who carries out the administrative responsibilities related to the renewable energy tracking system.

(7g) "Pyrolysis" means an industrial process that heats organic or waste material under pressure in an oxygen-starved environment to break the material down into gases, liquid and solid residues.

(7r) "Renewable energy certificate" means an electronic certificate representing one MWh of total renewable energy from a certified renewable facility that meets all of the following requirements:

(a) The MWh is physically metered with the net generation measured at the certified renewable facility's bus bar.

(b) The MWh represents renewable energy that is delivered to a retail customer with the retail sale measured at the customer's meter, ignoring the transmission and distribution losses between the bus bar and the customer's meter.

(c) The MWh is tracked in the renewable energy tracking system.

(d) The facility meets the applicable requirements of ss. PSC 118.03 and 118.04.

(8) "RRC" means a renewable resource credit.

(9) "Renewable energy tracking system" means a program that tracks the selling, transferring, purchasing, and retiring of renewable energy certificates and RRCs under s. 196.378. (3) (a), Stats., and meets the criteria in s. PSC 118.06.

(10) "Renewable resource credit" means either of the following:

(a) One renewable energy certificate that exceeds an electric provider's minimum percentage requirement specified in s. 196.378 (2) (a), Stats., and meets the applicable requirements of ss. PSC 118.03 and 118.04.

(b) An electronic certificate representing one MWh of displaced conventional electricity, as calculated under s. PSC 118.09.

(11) "Retail customer" means a customer that receives retail electricity in Wisconsin.

(14) "Solar light pipe" means a device that concentrates and transmits sunlight through a roof to an interior space, employing highly-reflective material inside the device to focus and direct the maximum available sunlight to the interior space.

(15) "Solar water heater" means a device that concentrates and collects solar radiation to heat water for domestic use, pool heating, space heating, or ventilation air heating.

(16) "Synthetic gas" means gas created by plasma gasification or pyrolysis.

(17) "Tracking system account" means the account that the program administrator maintains in order to track the creation,

40

sale, transfer, purchase, and retirement of a renewable energy certificate or an RRC by a renewable energy tracking system participant.

History: CR 00–065: cr. Register July 2001, No. 547 eff. 8–1–01; CR 06–112: r. (5) and (9), am. (7), (10) and (11), r. and recr. (13) Register May 2007 No. 617, eff. 6–1–07; CR 10–147: renum. (1) to be (1a) and am., cr. (1e), (1m), am. (2), cr. (3m), am. (4), cr. (5), (5m), am. (6), cr. (6g), (6r), am. (7), cr. (7g), (7r), (9), renum. (10) to be (10) (intro.) and am., cr. (10) (a), (b), renum. (12) to be (17) and am., r. (13), cr. (14) to (16) Register March 2012 No. 675, eff. 4–1–12; republished to insert text inadvertently excluded from (4) Register January 2014 No. 697.

PSC 118.025 Renewable resource designation. Biogas is a renewable resource under s. 196.378 (1) (h) 2., Stats.

History: CR 10–147: cr. Register March 2012 No. 675, eff. 4–1–12.

PSC 118.03 Facilities eligible for the minimum percentage requirement and for creating renewable resource credits. **(1)** An electric provider may use the output of a renewable facility to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., or to create an RRC for renewable energy only if the renewable facility that is the source of the electric provider's renewable energy meets all of the following requirements:

(a) The energy output of the renewable facility is physically metered and the accuracy of the metering is subject to verification by the program administrator or the commission.

(b) The renewable facility registers with, and is certified by, the commission under s. PSC 118.05.

(c) The renewable facility is owned or operated by the electric provider, which sells the renewable energy to its retail customers or members, or the renewable facility supplies or allocates its energy under an executed wholesale purchase contract to the electric provider, which sells the renewable energy to its retail customers or members.

(2) An electric provider may create an RRC for conventional electricity displaced by the use of a non–electric facility only if the non–electric facility meets all of the following requirements:

(a) Is registered with, and is certified by, the commission under s. PSC 118.055.

(b) Was placed in service on or after June 3, 2010.

(c) Will replace or reduce the use of an electric device used for the same purpose at the same location as the non–electric facility.

(d) Satisfies any other condition established by the commission consistent with s. 196.378 (3) (a) 1m., Stats.

(3) An electric provider may only use the renewable portion of the production from a facility using both a renewable and conventional fuel, based on the relative energy content of the fuels, to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., or to create RRCs.

(4) (a) An electric provider may under par. (b) use the production of a facility that has contracted with a producer of biogas or synthetic gas for ownership of the gas and that has sufficient contracts to deliver the gas to the facility, according to the resulting number of MWh that the facility generates or the amount of conventional electricity that the facility displaces.

(b) An electric provider may use the production of a facility that satisfies par. (a) to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., or to create an RRC if the electric provider demonstrates all of the following:

1. The gas producer meters the amount of gas delivered, using metering devices that comply with ss. PSC 134.27 and 134.28.

2. The gas producer measures the heat content of the gas at least monthly.

3. The facility complies with sub. (1) or (2).

History: CR 00–065: cr. Register July 2001, No. 547 eff. 8–1–01; CR 06–112: r. (2) and (3) (a), am. (3) (b) Register May 2007 No. 617, eff. 6–1–07; CR 10–147: am. (title), (1) (intro.), (a), cons. and renum. (1) (c) 1. and 2. to be (1) (c) and am., cr. (2), renum. (3) (b) to be (3) and am., cr. (4) Register March 2012 No. 675, eff. 4–1–12.

PSC 118.04 Creation and transfer of renewable energy certificates and renewable resource credits. **(1)** A renewable energy certificate or an RRC is used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats., in the compliance period for which the electric provider retires the renewable energy certificate or RRC, regardless of the date on which the renewable energy certificate or RRC is retired in the renewable energy tracking system.

EXAMPLE: An RRC created for renewable energy generated in 2011 may be used to satisfy an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats., in compliance years 2011 through 2015. An RRC created in 2011 may be used for compliance year 2015 even if the RRC is not retired until 2016.

(1m) For purposes of determining how long a renewable energy certificate or an RRC is eligible to be used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats.:

(a) A renewable energy certificate is created when the renewable facility generates the renewable energy.

(b) An RRC for renewable energy is created when the renewable facility generates the renewable energy.

(c) An RRC for displaced conventional electricity is created in the year in which the use of the certified non–electric facility displaces conventional electricity.

(2) (e) Renewable energy or displaced conventional electricity that would meet the definition of an RRC under s. PSC 118.02 (10), except that it consists of less than one MWh, shall constitute a fraction of an RRC. A fractional RRC may not be smaller than 0.01 MWh.

(f) Two or more electric providers may jointly purchase or sell a renewable energy certificate or an RRC.

(g) 1. An RRC created before January 1, 2004, may be sold or used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats. The RRCs described in this subdivision may not be used after December 31, 2011, as provided in s. 196.378 (3) (c), Stats.

2. Renewable energy generated on or after January 1, 2004, but produced by a renewable facility that was placed into service before January 1, 2004, may only be used to create an RRC if the renewable energy constituted an incremental increase in output from the renewable facility due to capacity improvements that were made on or after January 1, 2004, as provided in s. 196.378 (3) (a) 2., Stats. The RRCs described in this subdivision may not be used to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., after the fourth year after the year in which the credit is created, as provided in s. 196.378 (3) (c), Stats. If the renewable facility was originally placed in service before January 1, 2004, but is entirely replaced with a new and more efficient facility, all of the output from the new facility constitutes an incremental increase and may be used to create RRCs.

3. An RRC created on or after January 1, 2004, that is produced by a renewable facility placed into service on or after January 1, 2004, may be sold or used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats. The RRCs described in this subdivision may not be used to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., after the fourth year after the year in which the credit is created, as provided in s. 196.378 (3) (c), Stats.

4. An RRC created for displaced conventional electricity may be sold or used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats. The RRCs described in this subdivision may not be used to meet a minimum percentage requirement under s. 196.378 (2) (a), Stats., after the fourth year after the year in which the credit is created, as provided in s. 196.378 (3) (c), Stats.

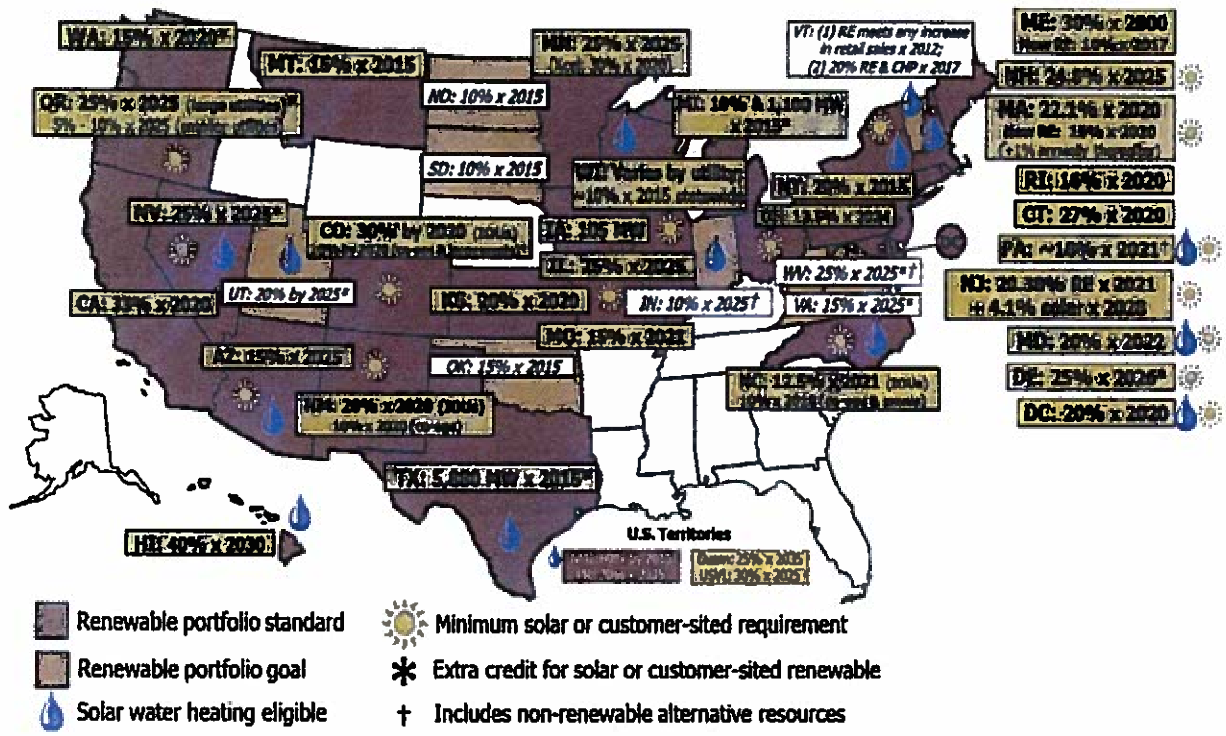
5. A renewable energy certificate that is not an RRC may not be used to meet an electric provider's minimum percentage requirement under s. 196.378 (2) (a), Stats., for a compliance

61

Renewable Portfolio Standards

29 states and DC have adopted Renewable Portfolio Standards (RPS) with mostly ambitious targets; 8 others have renewable goals

- Most MISO states have targets of 10% to 25% over the next 10-15 years



Source: Department of Energy, Database for State incentives for Renewables & Energy Efficiency (DSIRE), March 2013

Federal tax credits:

- Production tax credit (PTC) of $22/MWh for wind, geothermal, biomass
  Deadline for in-service extended through 2013
- Investment tax credit (ITC) of 30% for solar, fuel cells, and small wind, with a cash grant option
  Recently allowed PTC-eligible resources

The Brattle Group

62

The U.S. Department of Energy and the North Carolina Solar Center are excited to announce that a new, modernized DSIRE is under construction. The new version of DSIRE will offer significant improvements over the current version, including expanded data accessibility and an array of new tools for site users. The new DSIRE site will be available in the summer of 2014. Staff are currently working hard on the new DSIRE and are unfortunately only able to make minimal updates to the DSIRE website at this time. We apologize for any inconvenience and thank you for using DSIRE.

DSIRE™

Database of State Incentives for Renewables & Efficiency

05/01/2014

Minnesota

Incentives/Policies for Renewables & Efficiency

Renewables Portfolio Standard Like 3

Last DSIRE Review: 06/04/2013
Program Overview:

State:	Minnesota
Incentive Type:	Renewables Portfolio Standard
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Hydrogen, Co-Firing, Anaerobic Digestion
Applicable Sectors:	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative
Standard:	Xcel Energy: 31.5% by 2020 Other IOUs: 26.5% by 2025 Other utilities: 25% by 2025
Technology Minimum:	Wind or Solar (Xcel only): 25% by 2020; maximum of 1% from solar IOUs: 1.5% from solar by 2020, 10% of which must be met with systems 20 kW or less Statewide goal: 10% solar by 2030
Credit Trading:	Yes (M-RETS); some limitations apply
Credit Transfers Accepted From:	None

63

Credit Transfers Accepted To:	M-RETS into MIRECS, NAR, NC-RETS (Refers to tracking system compatibility only, not RPS eligibility. Please see statutes and regulations for information on facility eligibility)
Authority 1:	Minn. Stat. § 216B.1691
Date Enacted:	02/22/2007 (subsequently amended)
Date Effective:	02/22/2007
Authority 2:	PUC Order, Docket E-999/CI-04-1616
Date Enacted:	12/18/2007
Date Effective:	12/18/2007
Authority 3:	PUC Order, Docket E-999/CI-04-1616
Date Enacted:	12/03/2008
Date Effective:	2007 Compliance Year
Authority 4:	H.F. 729
Date Enacted:	5/23/2013
Date Effective:	5/24/2013

Summary:

Minnesota enacted legislation in 2007 that created a renewable portfolio standard (RPS) for Xcel Energy, created a separate RPS for other electric utilities,* and modified the state's existing non-mandated renewable-energy objective. In 2013, further legislation (H.F 729) was enacted to create a 1.5% solar standard for public utilities, a distributed generation carve-out, and a solar goal for the state. For the purpose of calculating the solar requirement, the following types of customers are not included: iron mining extraction and processing facilities, including scram mining; and paper mills, wood product manufacturers, sawmills, or oriented strand board manufacturers.

Eligible Technologies

Electricity generated by solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass -- which includes landfill gas, anaerobic digestion, and municipal solid waste -- is eligible for the standards and the objective. The definition of eligible biomass was refined slightly in 2008 by S.F. 2996 to include the organic components of wastewater effluent and sludge from public treatment plants, with the exception of waste sludge incineration. After January 1, 2010, hydrogen must be generated by other eligible renewables in order to be eligible.

Xcel Energy Standard

The standard for Xcel Energy requires that eligible renewable electricity account for 31.5% of total retail electricity sales (including sales to retail customers of a distribution utility to which Xcel Energy provides wholesale service) in Minnesota by 2020. Of the 31.5% renewables required of Xcel Energy in 2020, 1.5% must be met with solar PV (10% of which must be met with systems of 20 kW or less) , at least 25% must be generated by wind-energy or solar energy systems, with solar limited to no more than 1% of the requirement. In effect, this means that the wind standard is at least 24%, 1.5% must be met with solar, and solar may contribute up to another 1%, and the "remaining" 5% may be generated using other eligible technologies.

Wind energy and biomass energy contracted for or purchased by Xcel Energy pursuant to Minn. Stat. § 216B.2423 et seq. is eligible under the RPS. The RPS schedule for Xcel Energy is as follows:

- 15% by 12/31/2010
- 18% by 12/31/2012

- 25% by 12/31/2016
- 31.5% by 12/31/2020 (including 1.5% solar)

Standard for Non-Xcel Public Utilities

The standard for other public utilities requires that eligible renewable electricity account for 26.5% of retail electricity sales to retail customers in Minnesota by 2025. Of this electricity, 1.5% must be solar photovoltaics by 2020, and 10% of the solar standard must be met with systems of 20 kW or less.

- 12% by 12/31/2012
- 17% by 12/31/2016
- 21.5% by 12/31/2020 (including 1.5% solar)
- 26.5% by 12/31/2025 (including 1.5% solar)

Standard for Non-Public Utilities

The standard for other Minnesota utilities requires that eligible renewable electricity account for 25% of retail electricity sales to retail customers (and to retail customers of a distribution utility to which the one or more of the utilities provides wholesale service) in Minnesota by 2025. The RPS schedule for other Minnesota utilities is as follows:

- 12% by 12/31/2012
- 17% by 12/31/2016
- 20% by 12/31/2020
- 25% by 12/31/2025

Renewable Energy Certificates (RECs)

The 2007 legislation required the Minnesota Public Utilities Commission (PUC) to establish a program for tradable RECs by January 1, 2008. The PUC approved the Midwest Renewable Energy Tracking System (M-RETS) for this purpose and required all utilities to register renewable generation assets by March 1, 2008. The program treats all eligible renewables equally and may not ascribe more or less credit to energy based on the state in which the energy was generated or the technology used to generate the energy. Only RECs recorded and tracked through the M-RETS can be used for compliance. Notably, Xcel Energy may not sell RECs to other Minnesota utilities for RPS-compliance purposes until 2021. For the purposes of the solar standard, only RECs associated with solar installed and generating in Minnesota on or after May 24, 2013 but before 2020 are eligible. In December 2007, the PUC made certain additional determinations for the operation of the REC trading system, listed below:

- RECs will have a trading lifetime of 4 years according to the year of generation (i.e., all credits generated during 2008, regardless of the month, expired at the end of 2012).
- The purchase of RECs through M-RETS may be used in utility green pricing programs, subject to the shelf life described above.
- Consistent with M-RETS operating procedures, RECs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)
- The PUC declined to issue a directive ascribing ownership of RECs where ownership is not addressed in power purchase agreements (PPAs), instead requiring utilities to pursue negotiations and settlements with the owners of generation units.

Compliance and Reporting

Utilities are required to file annual compliance reports with the PUC detailing their retail sales, REC retirements, and REC trading activities. If the PUC finds a utility is non-compliant, the commission may order the utility to construct facilities, purchase eligible renewable electricity, purchase RECs or engage in other activities to achieve compliance. If a utility fails to comply, the PUC may impose a financial penalty on the utility in an amount not to exceed the estimated cost of achieving compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits and proceeds must be deposited into a special account reserved for energy and conservation improvements. The PUC is authorized to modify or delay the implementation of the standards if the commission determines it is in the public interest to do so.

The Minnesota Division of Energy Resources posted a consolidated 2007 Compliance Report detailing the progress made by each utility in achieving the renewable energy objective (see below). Compliance reports from individual utilities for 2008-2011 are available from the PUC through the E-Docket System in Dockets E-999/PR-09-287 (2008), E-999/PR-10-267 (2009), ER-999/PR-11-189 (2010), and ER-999/PR-12-334 (2011). In 2013, the Division of Energy Resources published a compliance progress report for compliance through 2011, stating that utilities are on track to comply with 2012 goals.

In May 2011, the legislature passed S.F. 1197, which requires utilities to submit a report to the commission and legislative committees estimating the rate impact of the activities necessary for compliance. The first report was due in October 2011, and subsequent reports are included as part of the utilities' resource plans.

Statewide Solar Goal

H.F. 729 (2013) also created a statewide solar goal of 10% of retail electric sales from solar by 2030.

Renewable-Energy Objective - All Utilities (2005-2010)

S.F. 4 (2007) modified Minnesota's non-mandated, "good faith" renewable-energy objective. The revised objective, which applied to all utilities, called for eligible renewables to account for 1% of all retail electricity sales in 2005 and 7% of all retail sales by 2010. The PUC measured utilities' efforts to meet the objective to determine whether utilities are making the required "good faith" effort. In December 2008, the PUC issued an order clarifying how it would evaluate this "good faith" effort during the years (2006 - 2009) for which no benchmarks were defined by the statute. The order required utilities to retire renewable energy credits (RECs) equivalent to 1% of their annual retail sales for the 2007-2009 compliance years (i.e., the calendar year). In effect, this both established a mandatory baseline compliance benchmark and allowed utilities to bank RECs -- subject to the REC trading lifetime described above -- in preparation for meeting the more stringent 7% objective in 2010. It could also be interpreted as setting a precedent for addressing similar issues in future years. Only RECs recorded and tracked through the Midwest Renewable Energy Tracking System (M-RETS) could be used for compliance with the "good faith" objective. Docket E-999/CI-04-1616 remains open to address issues not covered during the first phase of rulemaking, as well as future implementation issues that may arise due to changes in national, state, or M-RETS policies and protocols.

**Other electric utilities that must comply with Minnesota's RPS are: public utilities providing electric service; generation and transmission cooperative electric associations; municipal power agencies; and power districts operating in the state.*

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The U.S. Department of Energy and the North Carolina Solar Center are excited to announce that a new, modernized DSIRE is under construction. The new version of DSIRE will offer significant improvements over the current version, including expanded data accessibility and an array of new tools for site users. The new DSIRE site will be available in the summer of 2014. Staff are currently working hard on the new DSIRE and are unfortunately only able to make minimal updates to the DSIRE website at this time. We apologize for any inconvenience and thank you for using DSIRE.

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05/01/2014

Wisconsin

Incentives/Policies for Renewables & Efficiency

Renewable Portfolio Standard

Like 4

Last DSIRE Review: 12/14/2012

Program Overview:

State:	Wisconsin
Incentive Type:	Renewables Portfolio Standard
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Light Pipes; Biomass Thermal; Densified Fuel Pellets; Pyrolysis; Synthetic Gas; Biogas, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Biodiesel, Fuel Cells using Renewable Fuels
Applicable Sectors:	Utility, Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative
Standard:	Statewide target of 10% by 2015; requirement varies by utility
Technology Minimum:	No
Credit Trading:	Yes (M-RETS); limitations apply
Credit Transfers Accepted From:	None

Credit Transfers Accepted To:	M-RETS into MIRECS, NAR, NC-RETS (Refers to tracking system compatibility only, not RPS eligibility. Please see statutes and regulations for information on facility eligibility)
Web Site:	http://psc.wi.gov/utilityInfo/electric/renewa...
Authority 1: Date Enacted: Date Effective:	Wis. Stat. § 196.378 10/27/1999 (subsequently amended) 12/31/2001
Authority 2: Date Effective:	Chapter PSC 118 06/01/2007
Authority 3: Date Enacted: Date Effective:	S.B. 273 05/19/2010 06/03/2010
Authority 4:	PSC Docket 1-AC-234
Authority 5: Date Enacted: Date Effective:	S.B. 81 07/05/2011 12/31/2015
Authority 6: Date Enacted: Date Effective:	CR 10-147 04/03/2012 04/01/2012

Summary:

In 1998 Wisconsin enacted Act 204, requiring regulated utilities in eastern Wisconsin to install to an aggregate total of 50 MW of new renewable-based electric capacity by December 31, 2000. In October 1999 Wisconsin enacted Act 9, becoming the first state to enact a renewable portfolio standard (RPS) without having restructured its electric-utility industry. Wisconsin's RPS originally required investor-owned utilities and electric cooperatives to obtain at least 2.2% of the electricity sold to customers from renewable-energy resources by 2012. Legislation enacted in March 2006 increased renewable energy requirements and established an overall statewide renewable energy goal of 10% by December 31, 2015. The requirements are as follows:

- For the years 2006, 2007, 2008 and 2009, each electric provider (including investor-owned and municipal utilities, and electric cooperatives) -- may not decrease its renewable-energy percentage below the electric provider's average renewable-energy percentage for 2001, 2002 and 2003.
- For the year 2010, each electric provider must increase its renewable-energy percentage by at least two points above the electric provider's average renewable-energy percentage for 2001, 2002 and 2003.
- For the years 2011, 2012, 2013 and 2014, each electric provider may not decrease its renewable-energy percentage below the electric provider's renewable-energy percentage for 2010.
- For the year 2015, each electric provider must increase its renewable-energy percentage by at least six points above the electric provider's average renewable-energy percentage for 2001, 2002 and 2003.
- For each year after 2015, each electric provider may not decrease its renewable-energy percentage below the electric provider's renewable-energy percentage for 2015.

Electric providers, wholesale suppliers and customers of electric providers may petition the PSC for an extension of a compliance deadline. By June 1, 2016, the Wisconsin Public Service Commission (PSC) must determine if the state has met a renewable-energy goal of 10% by December 31, 2015. If the goal has not been achieved, the PSC must indicate why the goal was not achieved and must determine how it may be achieved.

Eligible Technologies

Qualifying electricity generating resources include tidal and wave action, fuel cells using renewable fuels, solar thermal electric and photovoltaics (PV), wind power, geothermal, hydropower, and biomass (including landfill gas). In May 2010, the RPS was amended to allow certain resources that produce a measurable and verifiable displacement of conventional electricity resources to also qualify as eligible resources (i.e., non-electric resources which displace electricity). Furthermore, the new law permits electricity generated (or electricity displacement) by certain waste resource technologies to qualify for the standard. The PSC developed rules in Docket 1-AC-234 (effective April 2012) defining the additional eligible technologies, including: solar water heaters; solar light pipes; ground source heat pumps; and installations that generate thermal output from biomass, biogas, synthetic gas, densified fuel pellets, or fuel produced by pyrolysis. The rules also established standards for measuring and verifying non-electric technologies.

Renewable energy generated outside of Wisconsin is eligible, but the electricity must be used to meet a provider's retail load obligation in Wisconsin (i.e., it must be delivered to Wisconsin customers).

Electricity generated by hydropower receives special treatment. For small hydropower (less than 60 MW), utilities receive credit for the sum of (1) all hydropower purchased in a reporting year, (2) the average of the amounts of hydropower generated by facilities owned or operated by the utility for 2001, 2002 and 2003, adjusted to reflect the permanent removal from service of any of those facilities and adjusted to reflect any capacity increases from improvements made after January 1, 2004; and (3) the amount of hydropower generated in the reporting year by facilities owned or operated by the electric provider that are initially placed in service on or after January 1, 2004. As a result of S.B. 81 enacted in July 2011, beginning December 31, 2015 (the effective date of S.B. 81), electricity from large hydropower facilities (60 MW or more) can be counted toward the RPS requirement if the facility was placed in service on or after December 31, 2010. Facilities in Manitoba, Canada are eligible if certain requirements are met.

Renewable Energy Certificates and Renewable Resource Credits

Under the RPS, electricity providers may create and sell or transfer both Renewable Resource Credits (RRCs) and Renewable Energy Certificates (RECs).

- A REC is defined as a certificate representing one MWh of total renewable energy that is physically metered with the net generation measured at a certified renewable facility's bus bar **and** that is delivered to a retail customer with the retail sale measured at the customer's meter. Transmission and distribution losses between the bus bar and the customer's meter are ignored.
- An RRC is defined as either 1) a REC that exceed a utility's minimum requirements or 2) a certificate representing one MWh of displaced conventional electricity.

RRCs may be used in subsequent years; however, RECs that are not RRCs may only be used for compliance in the year that the REC was created. Existing installations that qualify as renewable energy resources are eligible to be counted towards a utility's compliance, however, only generation capacity (including incremental additions at existing installations) added after January 1, 2004 is eligible to generate tradable RRCs. An RRC created before January 1, 2004 could be used for compliance until December 31, 2011, after which it expired. An RRC generated after January 1, 2004 may be used for compliance up to 4 years after the year in which it was created.

The Wisconsin PSC was one of principal developers of the Midwest Renewable Energy Tracking System (M-RETS) to be used for this purpose. Public reports detailing utility progress under the RRC program are available here on the M-RETS web site. The PSC is also required to submit a report to the Wisconsin legislature and governor every other year evaluating the impact of the RPS on the rates and revenue requirements of utilities. The most recent report was released in June 2012. In November 2012, the PSC accepted electric provider compliance reports, finding all electric providers and aggregators to be in compliance with the 2011 requirements.

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The U.S. Department of Energy and the North Carolina Solar Center are excited to announce that a new, modernized DSIRE is under construction. The new version of DSIRE will offer significant improvements over the current version, including expanded data accessibility and an array of new tools for site users. The new DSIRE site will be available in the summer of 2014. Staff are currently working hard on the new DSIRE and are unfortunately only able to make minimal updates to the DSIRE website at this time. We apologize for any inconvenience and thank you for using DSIRE.

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05/01/2014

New Jersey

Incentives/Policies for Renewables & Efficiency

Renewables Portfolio Standard Like 9

Last DSIRE Review: 03/28/2013
Program Overview:

State:	New Jersey
Incentive Type:	Renewables Portfolio Standard
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells using Renewable Fuels
Applicable Sectors:	Investor-Owned Utility, Retail Supplier
Standard:	20.38% Class I and Class II renewables by energy year 2020-2021 + 4.1% solar-electric by energy year 2027-2028
Technology Minimum:	Solar-Electric: 4.1% by energy year 2027-2028 Offshore Wind: 1,100 MW (standard must be defined in % terms by BPU, sufficient to reach this level of generating capacity)
Credit Trading:	Yes (PJM-GATS)
Credit Transfers Accepted To:	PJM-GATS into MIRECS (Refers to tracking system compatibility only, not RPS eligibility. Please see statutes and regulations for information on facility eligibility)
Web Site:	http://www.njcleanenergy.com/renewable-energy...

72

Authority 1:	N.J. Stat. § 48:3-49 et seq.
Date Enacted:	1999 (subsequently amended)
Authority 2:	N.J.A.C. 14:8-1 & 14:8-2
Date Enacted:	2001 (subsequently amended)
Date Effective:	09/01/2001
Authority 3:	S.B. 1925
Date Enacted:	07/23/2012
Date Effective:	07/23/2012

Summary:

Note: In July 2012 New Jersey enacted S.B. 1925 substantially revising its solar carve-out. The summary below incorporates information on the changes made to the solar carve-out as well as the qualification of certain hydropower projects under the RPS. While it contains information on many of the most important changes made by the law, it is not exhaustive and lacks some details. Extensive rule making activity will be necessary to implement the various provisions contained in S.B. 1925.

New Jersey's renewable portfolio standard (RPS) -- one of the most aggressive in the United States -- requires each supplier/provider serving retail customers in the state to procure 22.5% of the electricity it sells in New Jersey from qualifying renewables by 2021 ("energy year" 2021 runs from June 2020 – May 2021). In addition, the standard also contains a separate solar specific provision which requires suppliers and providers to procure at least 4.1% of sales from qualifying solar electric generation facilities by Energy Year 2028.

As detailed in the table below, prior to A.B. 3520 enacted in 2010, the solar carve-out was stated as a percentage-based target that, when combined with other resource targets, resulted in a total renewable energy standard of 22.5% by 2021. The January 2010 legislation adjusted the solar portion of the standard to be stated in terms of gigawatt-hours (GWh), resulting in a revised schedule requiring 17.88% from Class I and 2.5% from Class II renewables by EY 2021 (together 20.38% by EY 2021), and an additional 5,316 GWh from solar-electric facilities by EY 2026. In 2012 the solar compliance schedule was reverted back to a percentage-based target of 4.1% by EY 2028 by S.B. 1925. The offshore wind provision added in August 2010 by S.B. 2036 is defined so that it will reduce the percentage of electricity sales that must be provided from other Class I renewable energy sources (see Class I description below). In other words, the addition of the offshore wind resource requirement will not increase the overall renewable energy targets.

The mandate sets different requirements for different types of renewable energy resources, termed "classes". "Class I" renewable energy is defined as electricity derived from solar energy, wind energy, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and -- with written permission of the New Jersey Department of Environmental Protection (DEP) -- certain other forms of sustainable biomass. As a result of S.B. 1925, Class I renewable energy also includes hydroelectric facilities of 3 MW or less that are: placed in service after July 23, 2012 (the effective date of S.B. 1925); located in the state and connected to the distribution system; and, certified as low-impact by a nationally recognized organization based on a system that includes a variety of minimum criteria.

"Class II" renewable energy is defined as electricity generated by hydropower facilities larger than 3 megawatts (MW) and less than 30 MW*, and resource-recovery facilities (i.e., municipal solid waste or MSW) located in New Jersey approved by the DEP. Electricity generated by a resource-recovery facility outside New Jersey qualifies as "Class II" renewable energy if the facility is located in a state with retail electric competition and the facility is approved by the DEP. Solar energy, while it remains an eligible Class I technology, occupies a special place as the only resource eligible for the solar electric component of the standard. Offshore wind, defined as a wind turbine located in the Atlantic Ocean and connected to the New Jersey electric transmission system, likewise also occupies a special place within the RPS.

The required percentages of each category and the total renewables percentage required are listed in the table below. The term EY refers to compliance period or "energy year" for the standard, which runs from June - May and is defined by the year in which an energy year ends. Note that for Basic Generation Service (BGS) contracts executed prior to July 23, 2012 the supplier's obligation is determined according to the standard in effect at that time (i.e., the A.B. 3520 energy-based standard). However, the ultimate statewide target for any year is determined by the S.B. 1925 targets and does not change regardless of this exemption. Thus any differences (i.e., deficits) arising from the pre-existing BGS contract exemption are distributed evenly across non-exempt sales.

Energy Year	Solar Carve-Out (A.B. 3520)**	Pre A.B. 3520/S.B. 1925 Solar Carve-Out**	Class I	Class II
EY 2005	--	0.0100% (pre-A.B. 3520)	0.740%	2.5%
EY 2006	--	0.0170% (pre-A.B. 3520)	0.983%	2.5%
EY 2007	--	0.0393% (pre-A.B. 3520)	2.037%	2.5%
EY 2008	--	0.0817% (pre-A.B. 3520)	2.924%	2.5%
EY 2009	--	0.1600% (pre-A.B. 3520)	3.840%	2.5%
EY 2010	--	0.2210% (pre-A.B. 3520)	4.685%	2.5%
EY 2011	306 GWh	0.3050% (pre-A.B. 3520)	5.492%	2.5%
EY 2012	442 GWh	0.3940% (pre-A.B. 3520)	6.320%	2.5%
EY 2013	596 GWh	--	7.143%	2.5%
EY 2014	772 GWh	2.050% (S.B. 1925)	7.977%	2.5%
EY 2015	965 GWh	2.450% (S.B. 1925)	8.807%	2.5%
EY 2016	1,150 GWh	2.750% (S.B. 1925)	9.649%	2.5%
EY 2017	1,357 GWh	3.000% (S.B. 1925)	10.485%	2.5%
EY 2018	1,591 GWh	3.200% (S.B. 1925)	12.325%	2.5%
EY 2019	1,858 GWh	3.290% (S.B. 1925)	14.175%	2.5%
EY 2020	2,164 GWh	3.380% (S.B. 1925)	16.029%	2.5%
EY 2021	2,518 GWh	3.470% (S.B. 1925)	17.880%	2.5%
EY 2022	2,928 GWh	3.560% (S.B. 1925)	--	--
EY 2023	3,433 GWh	3.650% (S.B. 1925)	--	--
EY 2024	3,989 GWh	3.740% (S.B. 1925)	--	--
EY 2025	4,610 GWh	3.830% (S.B. 1925)	--	--
EY 2026	5,316 GWh	3.920% (S.B. 1925)	--	--
EY 2027	5,316 GWh	4.010% (S.B. 1925)	--	--
EY 2028 +	5,316 GWh	4.100% (S.B. 1925)	--	--

As shown above, the general compliance schedule ends in 2021; however, the BPU will adopt rules to determine the minimum percentages for energy year 2022 and beyond. The revised solar schedule is similarly intended to extend beyond the 2028 target "to reflect an increasing number of kilowatt-hours to be purchased by suppliers or providers from solar electric power generators" in the state.

Because of the unique nature of offshore wind, a time line has not been established for the offshore wind carve-out. The BPU's adopted rules define a system where the standard for any given year is based on projected energy production from operating, eligible offshore wind facilities. In order to qualify as an eligible offshore wind facility, an applicant must submit a detailed project analysis to the BPU for approval. Among other things, the application must contain a proposal for pricing Offshore Wind Renewable Energy Credits (ORECs) as a fixed, flat rate or as a fixed price for every contract year. Suppliers will be required to purchase ORECs at a price and time period defined by the BPU.

Suppliers/providers may meet these requirements by submitting "Class I" renewable-energy certificates (Class I RECs), "Class II" RECs, Solar RECs (SRECs), and ORECs, all of which represent the environmental attributes of one megawatt-hour (MWh) of generation from an eligible facility. All RPS compliance must be submitted in the form of RECs, which will be issued by the PJM-Environmental Information Services (EIS), through PJM's Generation Attribute Tracking System (GATS). Both RECs and ORECs may be used for compliance during energy year in which they were generated or the following two compliance years. As a result of S.B. 1925, the lifetime for SRECs has been extended by an additional two years, so SRECs may be used for compliance during the year in which they were generated or the following four years. This extension of SREC lifetime applies only to SRECs created on or after July 23, 2012, the effective date of S.B. 1925. Any type of REC submitted for RPS compliance must be permanently retired.

Additional solar electricity may be used to fulfill any of the three required categories, while additional "Class I" electricity may be used to fulfill the "Class II" requirement. To qualify as "Class I" or "Class II" renewable energy, electricity must be generated within or delivered into the PJM region. "Class I" or "Class II" renewable energy delivered into the PJM region must be generated at a facility that began construction on or after January 1, 2003, in order to qualify. Solar facilities are eligible to produce SRECs for 15 years, termed the "qualification life", and thereafter may be issued Class I RECs, but not SRECs. Under the former rules suppliers/providers could not use RECs or SRECs associated with electricity generated at a customer-generator's premises unless the facility was eligible for net metering. However, S.B. 2936 (2007) amended the law to allow all facilities "connected to the distribution system in [New Jersey]", including but not limited to solar facilities, to generate RPS-eligible RECs or SRECs.

Prior to the adoption of S.B. 1925 in 2012, there was no explicit definition for "connected to the distribution system". With respect to solar-electric systems, S.B. 1925 defines the term to include: (1) net metered facilities, (2) facilities that meet the definition of "on-site generation"; (3) facilities eligible for aggregated net metering; (4) facilities owned or operated by a public utility approved by the BPU; (5) facilities connected to the distribution system at 69 kilovolts (kV) or less and approved by the BPU; and (6) facilities certified by the BPU and DEP as being located on a brownfield, an area of historic fill, or a closed landfill. The definition does not include any facility connected to the grid at a voltage of higher than 69 kV, unless the facility is a net metering facility.

Under (5) above, from EY 2014 - 2016, the BPU is generally only permitted to approve 80 MW of capacity in aggregate each year, and is not permitted to approve any single project with a capacity in excess of 10 MW. The law outlines a variety of parameters for BPU approval of grid-supply systems both before and after EY 2016. It also contains a slightly different path to approval for new grid-supply projects on agricultural land for which a PJM issued a System Impact Study on or before June 30, 2011. Finally, the law required the BPU to consider establishing a program to provide additional support for net metered solar facilities of three MW or larger, including those owned by a public utility. In March 2013 the BPU issued an order concluding its investigation into the matter with a finding that such a program was unnecessary.

If a supplier/provider is not in compliance for an energy year, the supplier/provider must remit an alternative compliance payment (ACP) and/or a solar alternative compliance payment (SACP) for the amount of RECs and solar RECs that were required but not submitted. The BPU determines prices for ACPs and SACPs, and reviews the prices at least once per year. The price of an ACP and an SACP is to be higher than the estimated competitive market cost of (1) the cost of meeting the requirement by purchasing a REC or solar REC, or (2) the cost of meeting the requirement by generating the required renewable energy.

The initial ACP and SACP levels were set by BPU order at \$50 per MWh and \$300 per MWh respectively in 2004. These levels were subsequently renewed several times without changes. The ACP remains unchanged at \$50 per MWh. The modern SACP was established by BPU order in December 2007 as a rolling eight-year schedule beginning in EY 2009 (i.e., one additional year added to the back end of the schedule each year). In July 2012 S.B. 1925 established a 15-year schedule for EY 2014 - EY 2028. The SACP for past years covered under the former BPU schedule and the 15-year schedule as adopted by S.B. 1925 are as follows:

- EY 2009: \$711 per MWh
- EY 2010: \$693 per MWh
- EY 2011: \$675 per MWh
- EY 2012 :\$658 per MWh
- EY 2013: \$641 per MWh
- EY 2014: \$339 per MWh
- EY 2015: \$331 per MWh
- EY 2016: \$323 per MWh
- EY 2017: \$315 per MWh
- EY 2018: \$308 per MWh
- EY 2019: \$300 per MWh
- EY 2020: \$293 per MWh
- EY 2021: \$286 per MWh
- EY 2022: \$279 per MWh
- EY 2023: \$272 per MWh
- EY 2024: \$266 per MWh
- EY 2025: \$260 per MWh
- EY 2026: \$253 per MWh
- EY 2027: \$250 per MWh
- EY 2028: \$239 per MWh

All SACPs and offshore wind ACPs must be refunded directly to ratepayers. However, revenue generated by payment of the Class I and Class II renewable energy ACPs must be used to fund renewable-energy projects through the New Jersey Clean Energy Program. Prior to the enactment of A.B. 3520, SACP revenue was also required to be directed to funding solar projects. In addition, prior to the enactment of the Solar Advancement Act of 2010, the BPU was required to freeze the solar energy requirement if it determined that the total cost of solar incentives during a reporting year exceeded 2% of the total retail price of electricity during that reporting year. This provision has now been removed and is no longer in effect.

Each supplier/provider is required to file an annual report with the BPU by October 1, demonstrating that the requirements for the preceding energy year (ending May 31 of the same calendar year) have been met. The Solar Advancement Act of 2010 also changed the classification of a compliance period from a "reporting year" to "energy year". Failure to comply with any provision of the RPS may result in suspension of the supplier's license, financial penalties, disallowance of recovery of costs in rates, and/or prohibition on accepting new customers.

History

New Jersey's RPS was originally adopted in 1999 as part of the state's electricity restructuring legislation with initial renewables targets of 4.0% Class I and 2.5% Class I or Class II resources by 2012. In 2004 the BPU amended the standard to require the renewable energy targets be met by May 2008, and to add a requirement that at least 0.16% of sales come from solar electricity as part of the overall Class I target of 4.0%.

The New Jersey Board of Public Utilities (BPU) made even more extensive revisions to the RPS in April 2006, significantly increasing the required percentages of Class I, Class II, and solar resources towards an ultimate requirement of 22.5% renewables, including 2.12% solar, by May 2021. In December 2007 the BPU issued a far-reaching order (BPU Solar Transition Order) directing that further changes be made to many of the details of the RPS in an effort to increase the effectiveness and efficiency of New Jersey's solar energy policies. Formal rule amendments associated with many of these changes became effective in 2009, although the broader renewable energy targets were not affected. As noted above, during 2010 the solar carve-out was redesigned and expanded and the offshore wind requirement was also added, while in 2012 additional substantial changes were made largely affecting the solar carve-out.

**The administrative regulations under N.J.A.C. § 14:8-2.6 restrict the size of eligible Class II hydropower projects to 30 MW or less, though this restriction is not contained within the RPS statute.*

***The A.B. 3520 and pre-A.B. 3520 solar targets have been included for informational purposes and historical context. The A.B. 3520 targets continue to have some revelance in that they continue to apply to BGS provider contracts in existence prior to the enactment of S.B. 1925. All BGS contracts under a similar exemption contained in A.B. 3520 expired by May 31, 2012.*

Contact:

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The U.S. Department of Energy and the North Carolina Solar Center are excited to announce that a new, modernized DSIRE is under construction. The new version of DSIRE will offer significant improvements over the current version, including expanded data accessibility and an array of new tools for site users. The new DSIRE site will be available in the summer of 2014. Staff are currently working hard on the new DSIRE and are unfortunately only able to make minimal updates to the DSIRE website at this time. We apologize for any inconvenience and thank you for using DSIRE.

DSIRE™
Database of State Incentives for Renewables & Efficiency

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy
IREC
NORTH CAROLINA Solar Center

05/01/2014

Massachusetts

Incentives/Policies for Renewables & Efficiency

Renewable Portfolio Standard

Like 3

Last DSIRE Review: 04/17/2013
Program Overview:

State:	Massachusetts
Incentive Type:	Renewables Portfolio Standard
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Renewable Fuels, Fuel Cells using Renewable Fuels
Applicable Sectors:	Investor-Owned Utility, Retail Supplier
Standard:	Class I (New Resources): 15% of by 2020 and an additional 1% each year thereafter Class II (Existing Resources): 7.1% in 2009 and thereafter (3.6% renewables and 3.5% waste-to-energy)
Technology Minimum:	In-state PV: Mandated Target of 400 MW
Credit Trading:	Yes (NEPOOL-GIS)
Web Site:	http://www.mass.gov/energy/rps

78

Authority 1:	M.G.L. ch. 25A, § 11F
Date Enacted:	11/25/1997
Date Effective:	4/2002
Expiration Date:	Not specified
Authority 2:	225 CMR 14.00
Date Enacted:	12/20/2010 (subsequently amended)
Date Effective:	01/07/2011
Authority 3:	225 CMR 15.00
Date Effective:	06/12/2009
Authority 4:	S.B. 2395 (Session Law Chapter 209)
Date Enacted:	08/03/2012
Authority 5:	Order Adopting Timetable for Long-Term Contracts, (Docket 13-57)
Date Enacted:	03/29/2013

Summary:

NOTE: In February 2013, the Massachusetts Department of Energy Resources (DOER) issued proposed changes to its RPS Class I and RPS Solar Carve-Out programs. The DOER accepted comments through March 25, 2013. In addition, the DOER has developed a draft Assurance of Qualification Guideline and an emergency regulation to provide clarity to the queuing and review process as Solar Carve-Out cap is approached. All drafts, comments, and comment submission information is available on the DOER web site.

Under the Class I Renewable Portfolio Standard, all retail electricity suppliers must provide a minimum percentage of kilowatt-hours (kWh) sales to end-use customers in Massachusetts from eligible renewable energy resources installed *after* December 31, 1997, according to the following schedule:

- 1.0% of sales by 12/31/2003
- 1.5% of sales by 12/31/2004
- 2.0% of sales by 12/31/2005
- 2.5% of sales by 12/31/2006
- 3.0% of sales by 12/31/2007
- 3.5% of sales by 12/31/2008
- 4.0% of sales by 12/31/2009
- 5.0% of sales by 12/31/2010 *
- 6.0% of sales by 12/31/2011
- 7.0% of sales by 12/31/2012
- 8.0% of sales by 12/31/2013
- 9.0% of sales by 12/31/2014
- 10.0% of sales by 12/31/2015
- 11.0% of sales by 12/31/2016
- 12.0% of sales by 12/31/2017
- 13.0% of sales by 12/31/2018
- 14.0% of sales by 12/31/2019
- 15.0% of sales by 12/31/2020, and an additional 1% of sales each year thereafter, with no stated expiration date

Eligible Class I resources include: photovoltaics (PV); solar thermal-electric energy; wind energy; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; energy generated by certain new hydroelectric facilities, or certain incremental new energy from increased capacity or efficiency improvements at existing hydroelectric facilities; low-emission advanced biomass power conversion technologies using fuels such as wood, by-products or waste from agricultural crops, food or vegetative material, energy crops, algae, biogas, liquid biofuels;** marine or hydrokinetic energy; and geothermal energy.

Starting in 2010, retail suppliers must provide a portion of the required renewable energy under the Class I Standard from qualified in-state, interconnected solar facilities. The DOER carried out a stakeholder process that began during second quarter of 2009 to determine the details of this requirement, called the Class I Solar Carve-Out. Final regulations were issued December 2010.

Qualifying solar facilities (officially known as "Solar Carve-Out Renewable Generation Units" in the regulations) must be 6 MW (direct current DC) or less, and must have become operational after December 31, 2007. Facilities that received funding prior to January 1, 2010 from the Massachusetts Renewable Energy Trust or more than 67% funding from the American Recovery and Reinvestment Act (except the federal grant in lieu of tax credit) are ineligible. The Solar Carve-Out Minimum Standard for compliance year 2012 is 0.163%. The Solar Carve-Out Minimum Standard for compliance year 2013 is 0.2744%.*** The Solar Minimum Standard is calculated by dividing the annual solar compliance obligation in megawatt hours (MWh) by the total RPS load obligation from the previous two years. The solar compliance obligation in turn is based on the difference in the SRECs generated during the past two years (see the DOER regulations for calculations and additional guidance). When 400 MW (DC) of qualifying solar facilities have been installed, no additional solar facilities will be qualified for the Solar Carve-Out, although they would be eligible to qualify as a RPS Class I Renewable facility and continue to satisfy the overall Class I Standard.

The DOER has established the qualification process for RPS Class I Renewable and Solar Carve-Out Renewable Generation Facilities in its regulations and provides forms and instructions on its website. The DOER will issue the Statement of Qualification (SQ) and once issued, the developer has four years to put the generation facility into operation. The regulations allow DOER to grant extensions, however the petitioner must submit a new SQ application. No SQ will be issued for Solar Carve-Out projects until all applicable permits are secured.

The Class II RPS requires all retail electricity suppliers to provide annually 3.6% of kWh sales to end -use customers in Massachusetts from Class II renewables, starting in 2009. Eligible Class II renewables include systems operating *before* December 31, 1997, that generate electricity using PV; solar thermal-electric energy; wind energy; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; energy generated by certain existing hydroelectric facilities up to 7.5 megawatts (MW) in capacity; low-emission advanced biomass power conversion technologies using fuels such as wood, by-products or waste from agricultural crops, food or vegetative waste, energy crops, biogas, liquid biofuels; marine or hydrokinetic energy; or geothermal energy. In August 2012, DOER has temporarily stopped considering woody biomass as a Class II eligible resource until a rulemaking is completed. The rulemaking is to consider the provisions from the Class I regulations relating to protecting forests and reducing greenhouse gas emissions.

In addition, there is a separate Class II Waste Energy Minimum Standard that requires all retail electricity suppliers to provide annually 3.5% of kWh sales to end-use customers in Massachusetts from waste energy**** starting in 2009. Eligible waste energy generation units must have and maintain a state approved recycling program, must comply with Massachusetts Department of Environmental Protection's air pollution and solid waste management regulations, and must allocate at least 50% of any revenue received from the sale of renewable energy certificates generated to its recycling programs.

Retail electricity suppliers demonstrate compliance by submitting, in an annual compliance filing to the DOER, documentation that Class I Renewable Energy Certificates (RECs), Solar Carve-Out Generation Certificates (SRECs) Class II RECs, and Class II Waste Energy Certificates have been secured.***** These certificates represent the environmental attributes of one megawatt-hour (MWh) of generation from an eligible facility under each class category. In order to facilitate a robust SREC market, that not only responds to market conditions but also provides price support, the DOER has created the Solar Credit Clearinghouse program.

Retail suppliers may pay the alternative compliance payment (ACP) if they are unable to procure enough renewable energy attributes, however the ACP rates are designed to be higher than the market price of RECs and SRECs. The DOER determined the initial ACP rate for each resource category. The ACP for Class I, Class II, and Class II Waste Energy increase (or decrease) annually based on the Consumer Price Index of the previous year. The Solar ACP will decrease only if DOER determines it is needed based on market conditions; they will not reduce it more than 10% in any given year. The Solar ACP was amended in December 2011 and now follows a 10-year schedule (final rules pending). See the DOER's Solar ACP 10-year Schedule for details. The following table provides the base year ACP rate and current ACP rates:

Alternative Compliance Payment Rates

Year	Class I	Class II	Class II Waste Energy	Solar Carve-Out
Base Year: Initial Rate/MWh	2003: $50.00	2009: $25.00	2009: $10.00	2010: $600.00
2009 Rate/MWh	$60.92	$25.00	$10.00	n/a
2010 Rate/MWh	$60.93	$25.00	$10.00	$600.00
2011 Rate/MWh	$62.13	$25.50	$10.20	$550.00
2012 Rate/MWh	$64.02	$26.28	$10.51	$550.00
2013 Rate/MWh	$65.27	$26.79	$10.72	$550.00

Massachusetts RPS compliance reports are available on the DOER website.

The MA DOER and the MA Department of Environmental Protection announced a new joint initiative in November 2011, Clean Energy Results Program. This program has several specific renewable energy goals, including by 2020 achieve 50 MW of new solar PV on landfills and brownfields, and support installation of at least three anaerobic digestors and/or CHP projects by 2014 with private partners, among others.

The Green Communities Act (S.B.2768) also requires that electric distribution companies solicit long -term contracts (defined as 10-15 years) for renewable energy (electricity, RECs, or both) two times between July 1, 2009 and December 31, 2012. Originally, the legislation required the renewable energy to be from within Massachusetts, however, in June 2010 the Department of Public Utilities issued emergency regulations (220 C.M.R. 17.00 Emergency) striking the in-state requirement, thereby allowing out-of-state renewable energy resources to submit bids. Massachusetts Department of Energy Resources issued the RFP in September 2010; bids were due in October and contracts will be submitted for approval in March 2011. Legislation passed in August 2012 amended the long-term contracting provisions, and an order released in March 2013 approved a timetable for two solicitations between January 1, 2013 and December 31, 2016.

S.B. 2768 also established the alternative energy portfolio standard (APS), which requires meeting 5% of Massachusetts' electric load with "alternative energy" by 2020. Legislation passed in August 2012 requires that the state's executive office of energy and environmental affairs study adding technologies that generate "useful thermal energy" to the list of eligible technologies under this standard. That study will be completed by the end of December 2012. For more information on the existing standard, see Alternative Energy Portfolio Standard.

** The Solar Carve-Out Minimum Standard was 0.0680% (e) of sales by 12/31/2010. This standard is a portion of the Class I standard, not an addition to the standard.*

*** In August 2012, the DOER issued the final biomass regulation after more than two years of studying, public input and review. See the "Biomass Policy Regulatory Process" web site for additional, specific information.*

**** For 2010, the Solar Carve-Out compliance obligation was approximately 30 megawatts (MW) (DC), equivalent to a Solar Carve-Out Minimum Standard of 0.0679%. The Solar Carve-Out compliance obligation for compliance year 2011 was approximately 69 MW, equivalent to a Solar Carve-Out Minimum Standard of 0.1627%. The 2012 Solar Carve-Out compliance obligation is approximately 71 MW. The 2013 Solar Carve-Out compliance obligation is approximately 118 MW.*

***** Waste energy is defined as the electrical energy created from combustion of municipal solid waste.*

******The respective renewable energy certificates (RECs) are issued by the New England Power Pool Generation Information System (NEPOOL-GIS) and are technically called GIS Certificates.*

History

Massachusetts' 1997 electric-utility restructuring legislation created the framework for a renewable portfolio standard (RPS). In April 2002, the Massachusetts Department of Energy Resources (DOER) adopted RPS regulations that required all retail electricity providers in the state to utilize new renewable-energy sources for at least 1% of their power supply in 2003, increasing to 4% by 2009. The RPS was significantly expanded by legislation enacted in July 2008 (Green Communities Act S.B. 2768); this legislation established two separate renewable standards -- a standard for "Class I" renewables, and a standard for "Class II" renewables -- as well as an alternative portfolio standard.

Contact:

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TAB 11

Manitoba Hydro

September 23, 2013

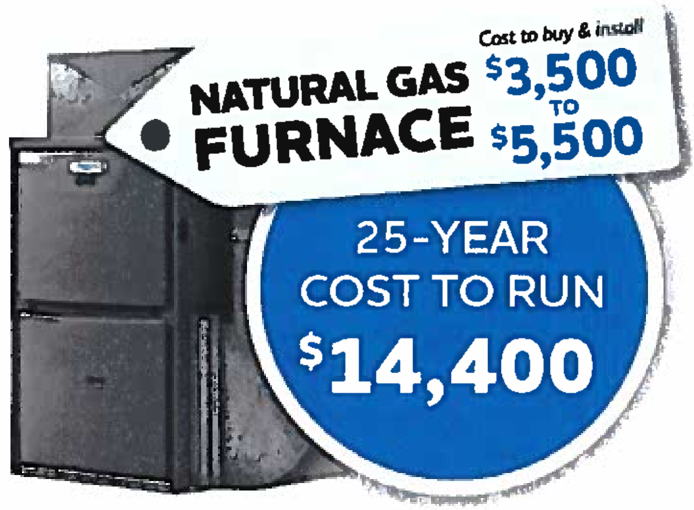
RE: LOWER YOUR ENERGY BILL WITH A NATURAL GAS HEATING SYSTEM

Dear Customer,

Our records indicate there is a natural gas service at your address that is potentially not being used for heating your home. We would like to take this opportunity to provide you with some information that could save you hundreds of dollars annually on your Manitoba Hydro energy bill. Most heating systems last over 20 years, which could mean thousands of dollars in savings over its lifetime.

Heating your home accounts for approximately 60% of your energy bill. Some heating systems cost more to buy and install but will cost less to run. Total life time cost of a heating system is important to consider when deciding what type of system should be used in your home. The total lifetime cost of a heating system is the cost to buy and install plus the cost to run.

You currently are using natural gas at your home for other appliances; because of this it makes a lot of sense to consider using it for heating your home. On the right is a heating cost comparison for a typical Manitoba household using a natural gas furnace versus an electric furnace.* Based on the comparison shown, the total life time cost of a natural gas heating system is $17,900 to $19,900 compared to an electric heating system which is $30,800 to $31,800. That is a savings of almost $13,000 over 25 years! Visit www.hydro.mb.ca/heating



** The cost to buy, install and operate indicated is an average and will vary depending on your home, specific heating needs, and other conditions. Cost to run is based on a natural gas cost of $0.2336/m3 and electricity cost of $0.0694/kWh.*

and use our interactive heating cost comparison calculator for a more personalized comparison of home heating costs based on the type, size and age of your home.

To further assist you in understanding your home heating options we have included a brochure on the different types of heating systems available and their approximate costs to purchase and operate. We recognize that replacing your heating system is an expensive purchase decision and that is why we are here to help. Manitoba Hydro has a number of Power Smart Financing programs that help make the purchase of a new heating system more affordable; we have included a brochure for more information. If electric heat is right for you, you may want to consider upgrading to a geothermal heating system to lower your energy costs.

Whether you choose to switch to a natural gas heating system or continue to heat with electricity, consider upgrading your home's insulation in order to reduce your heating costs. Power Smart can help, visit hydro.mb.ca for information, incentives and financing to assist you with your next insulation project.

If you have any questions regarding the information provided with this letter or any of our Power Smart programs please contact 204-480-5900 (in Winnipeg) or 1-888-MBHYDRO (1-888-624-9376) or email powersmartexpert@hydro.mb.ca.

Sincerely,

The Power Smart Expert
Manitoba Hydro