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La Capra Associates

NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

Technical Appendix 6

Export Markets

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This report contains information that has been deemed Commercially Sensitive Information and is, therefore, subject to a protective order.

PREPARED FOR

The Manitoba Public Utilities Board

PREPARED BY

La Capra Associates, Inc.
One Washington Mall, 9th Floor
Boston, MA 02108

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Technical Appendix 6: Export Markets

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Acronyms

Technical Appendix 6

AESO	Alberta Electric System Operator
EAR	External asynchronous resource
EEPF	Electricity Export Price Forecast
EIA	United States Energy Information Administration
EPO	Energy Price Outlook
GRE	Great River Energy
HOEP	Hourly Ontario Energy Price
IESO	Independent Electricity System Operator
LCA	La Capra Associates
LMP	Locational marginal price
MATS	Mercury and Air Toxics Standards
MH	Manitoba Hydro
MHEB	Manitoba Hydro Electric Board
MISO	Midcontinent Independent System Operator
NFAT	Needs For and Alternatives To
NSP	Northern States Power
OATT	Open Access Transmission Tariff
OTP	Otter Tail Power
RTO	Regional Transmission Organization
SEA	Strategic Energy Assessment
SOW	Scope of Work
US EPA	United States Environmental Protection Agency
US	United States
WPPI	Wisconsin Public Power, Inc.
WPS	Wisconsin Public Service Corporation

I. Introduction

A. Scope of Report

La Capra Associates (LCA) has prepared this Technical Appendix to address two elements of our Needs For and Alternatives To (NFAT) Scope of Work (SOW) and support other elements of our work that rely on the materials in this report. The two specific LCA SOW elements address here are:

Power Resource Planning and Economic Evaluation

8. *Evaluate the accuracy and completeness of Manitoba Hydro's export assumptions into MISO and other jurisdictions.*

Business Case and Risk Assessment

7. *Address the future US versus Canadian export opportunities.*

The material contained in this Technical Appendix also relies on information contained in LCA Technical Appendices 7, Export Contracts, and 8, Transmission, and the information prepared by Potomac Economic in its work regarding the Midcontinent Independent System Operator (MISO) markets.

The specific focus of this Technical Appendix is to assess the reasonableness of the export market representations and assumptions contained in Manitoba Hydro's (MH) economic modelling and its SPLASH model for the alternative development cases.

B. Historical Context for Export Markets for Manitoba Hydro[1]

MH has a long history of exporting power to its United States (US) and Canadian neighbors. The nature of these markets has evolved significantly as MH's systems and neighboring systems have developed. The annual history of MH energy exports (MWhs) and revenues from those exports is depicted in Figure 6-1.

MH's exports began in 1970 with the completion of the Kettle Generation facility and the first 230 kV interconnection to the US, a line to North Dakota developed jointly with Northern States Power (NSP), Otter Tail Power (OTP) and Minnkota Power. By 1980, Long Spruce and Jenpeg Generation facilities, Bipole I and II, and two transmission line

[1] This section relies on information from Manitoba Hydro's website at http://www.hydro.mb.ca/corporate/history/history.shtml?WT.mc_id=2114 and from Presidential Permit documents for the US interties.

additions to Minnesota (a 230 kV line and a 500 kV line) with NSP, Minnkota Power and Minnesota Power & Light had been added, leading to the substantial increase in energy exports beginning at that time. Three 230 kV connections to Canadian neighbors (two to Saskatchewan and one to Ontario) were installed in this period, as well.

By 1995, the addition of the Limestone Generation station and further upgrades to the transmission lines to the US added to MH's annual energy exports. Subject to variation in water conditions, MH export levels remain at or near the 10,000 GWh/yr. levels first attained at that time. One additional US interconnection was added in 2002 (a 230 kV line to North Dakota with NSP and OTP) and the Wuskwatim Generation facility was completed in 2012.

Prior to 2005, the market for MH's export power involved direct interactions with neighboring utilities on a bilateral basis, with NSP being the most significant. In 2005, MISO began operations of its competitive wholesale market, adding additional opportunities for exports into this market. The MISO market has continued to evolve and expand since that time.

Over the past decade, MH exports generally have been between 10,000 to 12,000 GWh/yr., which is roughly 40% to 50% of sales to domestic customers during that period.

Along with increasing energy sales, MH export revenues increased significantly through much of this period. Although export revenues have declined in recent years due to the decline in wholesale market prices resulting from the recession and lower natural gas prices, MH continues to receive hundreds of millions of dollars of power export revenues each year.

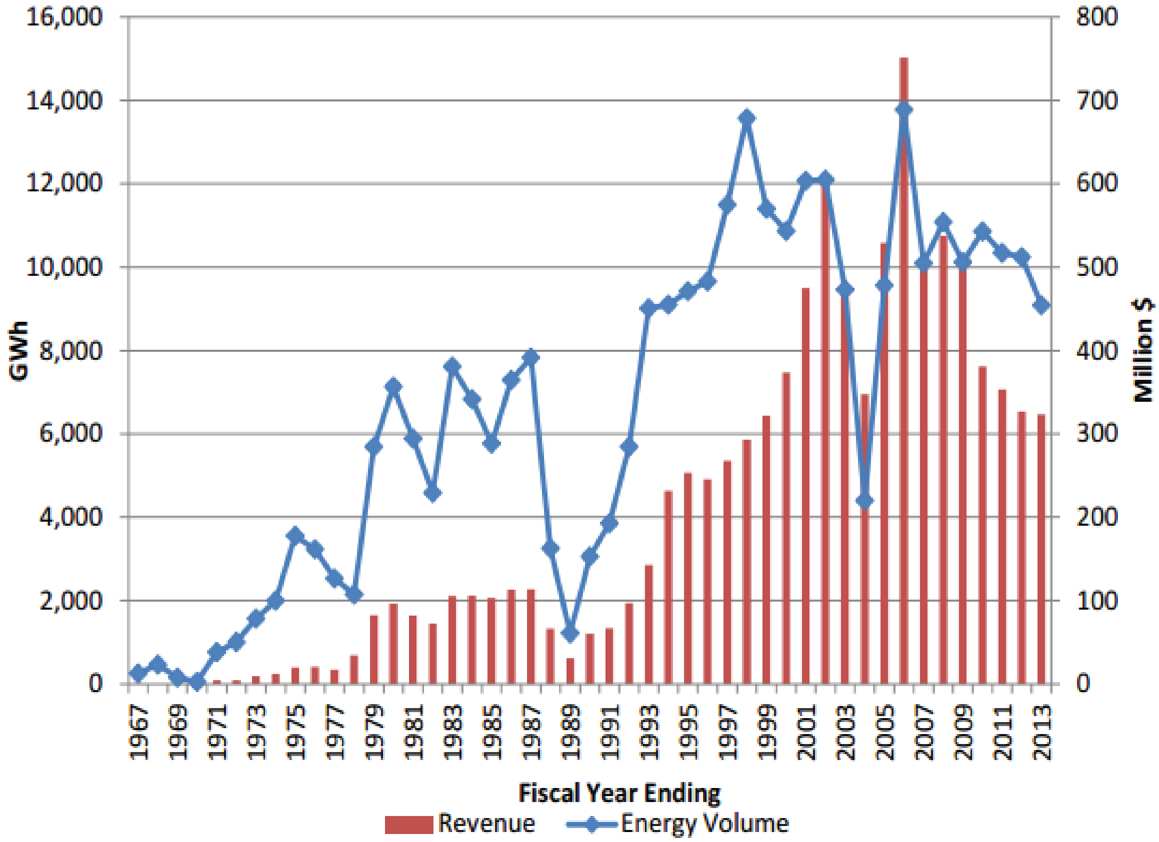

Figure 6-1: Manitoba Hydro Export Sales History[2]

As shown in Figure 6-2 below, over the past decade, about one-third of MH's total electricity revenue has come from exports. Its plan to build two new large hydro facilities and further expand the transmission capabilities to US markets creates the potential to extend its current position as a major exporter of hydro power well into the future. Figure 6-3 below shows the percentage of revenue from exports before and after the installation of Keeyask and Conawapa as part of the Preferred Development Plan according to MH's analysis as presented in the NFAT Submission.

[2] NFAT Submission, Chapter 5, Figure 5.3.

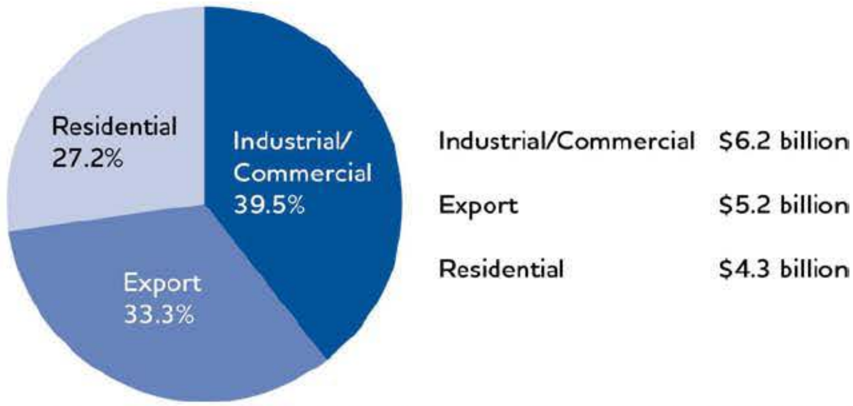

Figure 6-2: Manitoba Hydro electricity revenue sources-2002/03-2011/12.[3]

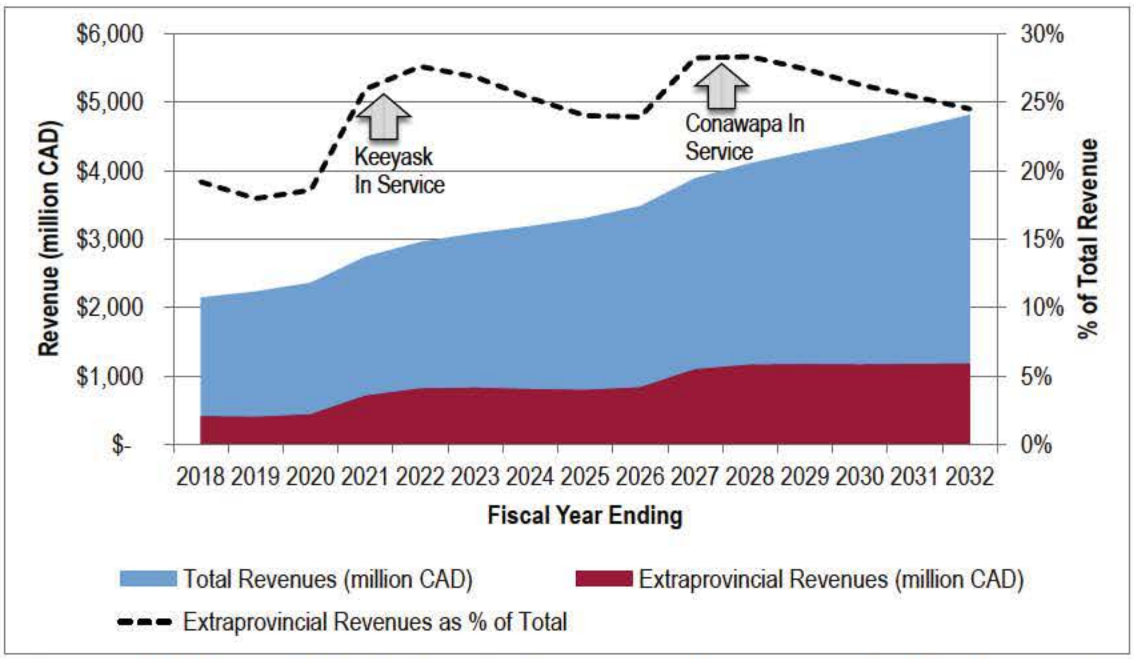

Figure 6-3: Forecasted total and extraprovincial revenues for the Preferred Development Plan from NFAT Submission.[4]

[3] Manitoba Hydro, "Electricity Exports," https://www.hydro.mb.ca/corporate/gif/electricity_revenue_sources.jpg.

[4] NFAT Submission, Appendix 11.4.

II. Power Services and Products for Export

This section of the report provides an overview of MH's export markets in terms of the different power products and services that MH sells. MH structures these products and services to reach different export market segments or take advantage of different market opportunities.

Fundamentally, there are four services or commodities that MH exports:

1) **Energy:** Actual electrical energy generated, as measured in MWhs.
2) **Capacity:** Ability of generation units to generate energy, as measured in MWs.
3) **Ancillary Services:** Services necessary to support the transmission of capacity and energy from generation resources to consumers while maintaining reliable power grid operation. These services include Regulation, Operating Reserve, and Black Start services.
4) **Environmental Attributes:** Additional value from energy from certain types of generators, generally either renewable or low-emission, as defined by environmental policies and regulations.

These components of power supply can be sold for export in a direct contractual arrangement with another utility, often referred to as a bilateral transaction. Alternatively, they can be sold in an organized market where multiple sellers can offer these components to multiple buyers through a competitive market structure, with the MISO competitive wholesale market being the market of this type with the largest transmission interconnection with MH.

Historically, MH's exports have been bilateral contracts. Organized wholesale markets are a relatively recent development, with the MISO Open Access Transmission Tariff (OATT) being instituted in 2002 and the MISO energy market being established in 2005. Bilateral contracts are expected to continue to be a major component of MH's power exports, with the open access transmission and competitive market place offering access to more potential buyers either through bilateral contracts or spot market transactions.

MH packages and sells combinations of these services through various products or contract offerings. The following provides a breakdown of different types of export products.

A. Long-Term Firm Products

MH determines its firm surplus power availability based on its resource planning criteria,[5] making all surplus dependable energy available for sale on a long-term basis, i.e. for sale under agreements with terms greater than one year. These sales are done on a bilateral basis with willing counterparties. The particular nature of the sale will be specified in the signed contract between the parties. Currently, MH makes the following types of sales on a long-term basis:[6]

- **System Power Sales:** Straight sales of energy and other services from MH's system to another party.
- **Diversity Sales:** Agreements where MH provides capacity and energy during the summer season in exchange for receiving capacity and energy in the winter season. These are done between parties for which load peaks at different times of year.
- **Exchange Agreement:** MH also has an exchange agreement with Minnesota Power that allows it to use firm transmission service to import up to 250 MWh/hour from the US and also allows Minnesota Power to store up to 250 GWh of excess wind energy each contract year.[7] However, this agreement is contingent on the building of new hydro generation and a new interconnection between MH and Minnesota.

Bilateral sales may include the sale of different types of services, and the pricing for different services may be separate or bundled together. Since firm transmission is needed to secure deliverability of power long-term, the sales may also include provisions to allow that firm transmission capacity to be used for additional sales at times when not needed for firm sales. For more details about MH's current contracts, please see Technical Appendix 7: Export Contracts.

[5] For more on how exports are incorporated into Manitoba Hydro resource planning, see Technical Appendix 1: Resource Planning.

[6] NFAT Submission, Appendix 9.3, pp. 15-22; NFAT Submission, Appendix 6.1. This list may not be comprehensive.

[7] NFAT Submission, Appendix 6.1, pp. 1-2.

Although it is not a straight export of power services, MH also has a contingency-reserve sharing agreement with MISO, requiring MH to supply MISO with 150 MW of contingency reserve (60 MW of that quantity spinning; 90 MW available within 15 minutes), and firm transmission is reserved on the Manitoba to US interconnection to supply these reserves.[8]

B. Medium-Term Products

Medium-term, in this case, refers to sales for terms longer than one day, but less than one year. When MH has assurance that water is available, it may make medium-term bilateral sales.[9] As with long-term sales, these sales may involve different services and the specific terms vary with the particular agreement.

MISO also runs a formal capacity market. Previously, MISO only provided a monthly voluntary capacity auction, but in 2013 it implemented an annual Planning Resource Auction where capacity for the subsequent planning year can be purchased and sold.[10]

C. Spot Market Sales

In this case, spot market sales are defined as sales with timeframes of one day or less. Sales can still be done on a bilateral basis or through structured markets for wholesale energy and ancillary services administered by regional transmission organizations (RTOs). Various export regions, including MISO, have such structured markets, and more details can be found in Section III below.

D. Special Provisions of Environmental Attribute Markets

Some buyers of MH exports are subject to generation portfolio standards that require portions of their supply to come from renewable sources or have other favorable environmental attributes. In some markets, these attributes are certified and traded in a market or exchange. In other markets, regulations can add value to power supplies

[8] *Id.*, Chapter 5, p. 18:2-6.

[9] Attachment CAC/MH I-051, "Review of Generation Planning Criteria," p. 28.

[10] For more, see: https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacy.aspx.

with favorable attributes in the resource planning process. Environmental attribute market demand depends entirely on how such markets are structured by the public policies that create them. For instance, the markets may clear annually or seasonally, banking of allowances may or may not be allowed, etc. Environmental attributes can be sold bilaterally on a long-term or short-term basis. Some policies, such as binding greenhouse gas reduction goals, may also create additional demand for clean energy, including hydro and wind, on a long-term basis. More on these policies and how MH participates in environmental attribute markets can be found in Technical Appendix 4: Environmental Issues and Policy. Specifics of the treatment of environmental attributes in MH's current long-term firm power sales are described in more detail in Technical Appendix 7: Export Contracts.

III. Export Market Regions

This section of the report provides an overview of MH's different regional export markets. MH has four major connected export markets:

- US, specifically the MISO region
- Saskatchewan
- Ontario
- Alberta

Each is addressed in turn.

A. MISO Region

The MISO market region is MH's primary export market, with over 85% of MH's exports sold to the US in recent years.[11] Reasons for MISO's importance as an export market include the size of the interconnection with MISO compared to interconnections with neighboring Canadian provinces,[12] the resource diversity between Manitoba and the MISO market,[13] and the close proximity of the Minneapolis-St. Paul metropolitan

[11] NFAT Submission, Chapter 5, p. 38:8-9.

[12] For more on the interconnections, see Technical Appendix 8: Transmission.

[13] NFAT Submission, Chapter 5, p. 17:14-18, and pp. 18-19.

area.[14] MISO is also a large market relative to Saskatchewan and Northwest Ontario and recently expanded with Entergy joining the market in December 2013. The map below shows the MISO reliability coordination footprint along with other RTO regions.

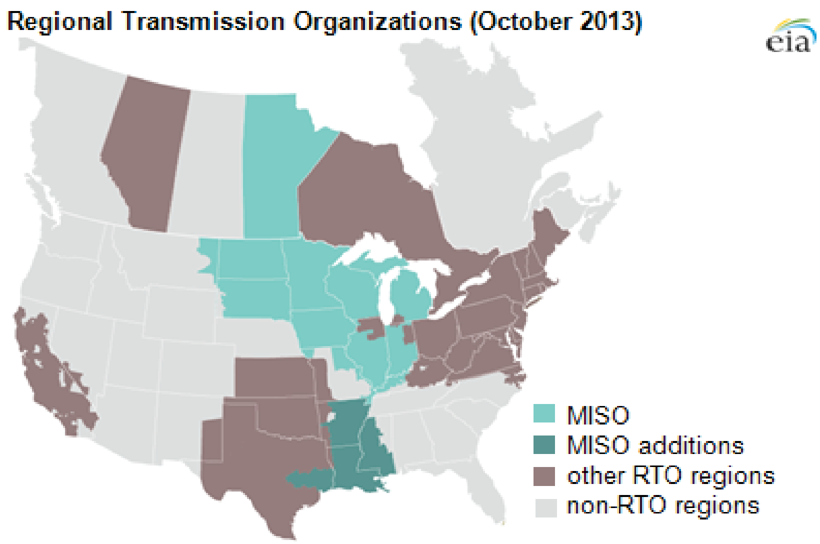

Figure 6-4: MISO reliability coordination footprint[15] and other RTO regions. [16]

The MISO region offers several markets into which MH can sell surplus power supply, including bilateral markets and structured markets administered by MISO as an RTO. Each of these types of markets is discussed in more detail below.

<u>Bilateral Market Opportunities within the MISO Footprint</u>

MH has long sold power to utilities in North Dakota, South Dakota, Minnesota, and Wisconsin through bilateral contracts with specific utilities operating in those states. None of these states allows retail choice such that consumers can choose their power suppliers.[17] Instead these states rely on vertically-integrated utilities with their own power supplies to meet the needs of the consumers in the state. The composition of

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[14] *Id.*, pp. 37:15-38:2.

[15] MISO's market footprint is smaller and does not include Manitoba.

[16] US Energy Information Administration (EIA), "Midcontinent Independent System Operator adding four new electric territories in December," http://www.eia.gov/todayinenergy/detail.cfm?id=13511&src=email.

these power supplies are subject to state regulation. Utilities in Minnesota, North Dakota, and South Dakota regularly file resource plans with their respective regulators.[18] Utilities in Wisconsin don't file individual plans, but the state releases and annual Strategic Energy Assessment (SEA).[19] Minnesota and Wisconsin also have binding renewable portfolio standards, and more details on this topic can be found in Technical Appendix 4: Environmental Issues and Policy.

MH is actively pursuing US exports through bilateral contract negotiations with MISO members, especially in Minnesota and Wisconsin. MH has partnered with Minnesota Power to build a new 500 kV interconnection, with a start date to coincide with the start of a new 250 MW power sale agreement.[20] MH is also in negotiations with Wisconsin Public Service Corporation (WPS) for a new power sale contingent on new transmission development. Wisconsin is seen as an attractive market since historically it has slightly higher prices than Minnesota and would broaden MH's export market—i.e. more market customers increases competition.[21]

MH still faces challenges reaching the Wisconsin market. WPS had expressed interest in funding the new 500 kV interconnection. However, WPS recently notified MH it was no longer interested in funding new transmission, leaving MH faced with the prospect of financing more than half of the US portion of the new transmission interconnection even though it will not take more than 49% ownership of US transmission assets for policy reasons.[22]

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[17] EIA, "Electricity Retail Choice States," http://www.eia.gov/todayinenergy/detail.cfm?id=6250.

[18] See for example: Montana-Dakota Utilities 2013 Integrated Resource Plan at http://www.montana-dakota.com/docs/default-source/2013-irp/2013-mdu-irp-report---volume-i.pdf?sfvrsn=0 and OTP's 2013 Integrated Resource Plan at https://www.otpco.com/about-us/environmental-commitment/integrated-resource-plan/.

[19] NFAT Submission, Chapter 6, p. 8:11-13.

[20] *Id.*, p. 33:7-8.

[21] *Id.*, p. 3:10-12.

[22] *Id.*, Executive Summary, p.7:9-21.

If a deal with WPS does not materialize, MH "would consider alternative arrangements in all markets including Minnesota, Wisconsin, North Dakota, Saskatchewan, and Ontario."[23]

Despite the size of the markets within the MISO footprint, MH currently has long-term contracts for power sales to a limited number of counterparties in the region. The following provides a summary of the operations of several of these entities.

Minnesota Power

Minnesota Power is a utility with a 26,000 sq. mi. service territory in northeastern Minnesota, as shown in the map below. Minnesota Power serves about 144,000 residential and commercial customers, 16 municipalities, and several large industrial customers.[24] Its 2012 average retail rates were 5.97 cents/kWh.[25]

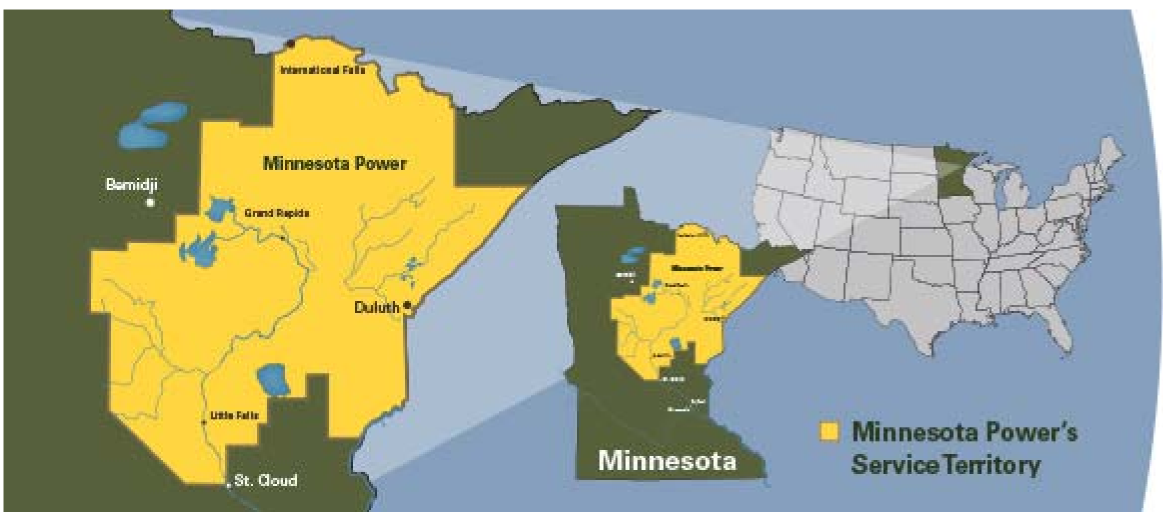

Figure 6-5: Minnesota Power's service territory.[26]

More than half of Minnesota Power's load is industrial, leading to a very high load factor of about 80%. It is a winter peaking system and had a peak load of about 1,800 MW and energy requirements of about 11,000 GWh in 2012.[27]

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[23] LCA/MH I-018.

[24] Minnesota Power, "About Us," http://www.mnpower.com/Company/AboutUs.

[25] Minnesota Power, 2013 Resource Plan, http://www.mnpower.com/Environment/ResourcePlan, p 1.

[26] Minnesota Power, "Coverage Map," http://www.mnpower.com/Company/CoverageMap.

Historically, Minnesota Power's generation portfolio has been dominated by coal, especially from its Boswell coal plant, which currently serves about 50% of its supply needs.[28]

In the future, according to its most recent resource plan, Minnesota Power expects modest load growth of about 0.7% annually through 2025.[29] It plans to diversify its portfolio with natural gas and renewable energy, but expects to remain heavily reliant on coal generation for the foreseeable future.

In recent years, the United States Environmental Protection Agency (US EPA) has been in the process of proposing, finalizing and implementing a series of regulations aimed at curbing harmful emissions from power plants. The Mercury and Air Toxics Standards (MATS) rule is one of the more impactful regulations on coal-fired generation, requiring costly emissions control equipment on all 25 MW or larger units by the compliance deadline in 2016. As a result of MATS and other concurrent new regulations, coal-fired units throughout the US are facing decisions about whether to make large capital investments in retrofits in the next few years or to retire.

The Boswell facility already has environmental controls installed for MATS compliance. Some of Minnesota Power's smaller coal-fired units, such as Laskin and Taconite Harbor 3, have been proposed for retirement. Minnesota Power's long-term goal is to achieve an energy mix that is about one-third renewable, one-third natural gas/other, and one-third coal.[30] However, even under Minnesota Power's preferred plan coal provides more than half of its energy requirements in 2027.[31] Future supply and demand projections for Minnesota Power's preferred plan are shown in the charts below.

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[27] Minnesota Power, "2013 Resource Plan," http://www.mnpower.com/Environment/ResourcePlan, pp 25, 71.

[28] *Id.*, p 30.

[29] *Id.*, p 24.

[30] *Id.*, p 2.

[31] *Id.*, p 64.

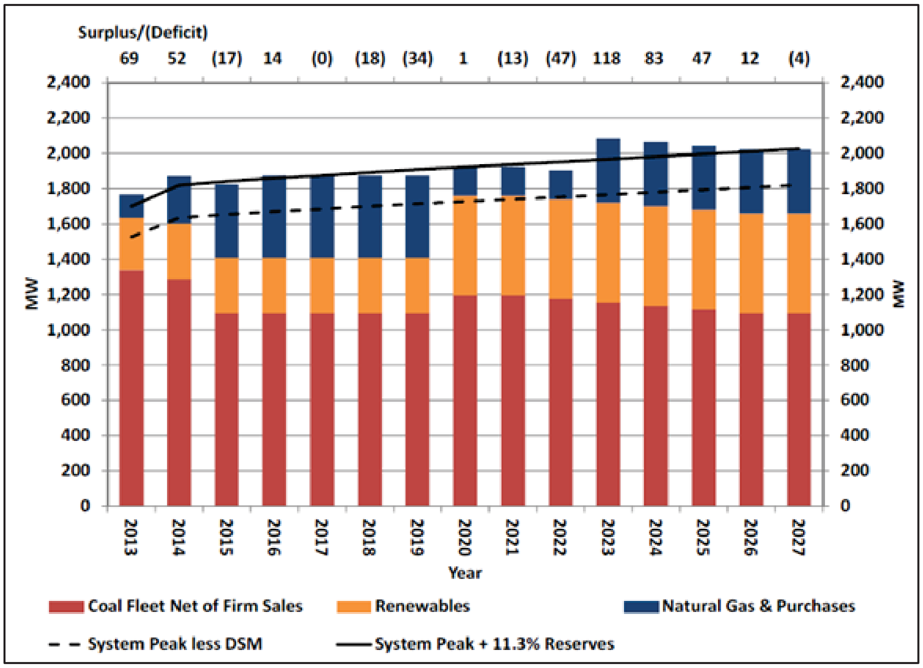

Figure 6-6: Minnesota Power Preferred Plan summer season capacity outlook.[32]

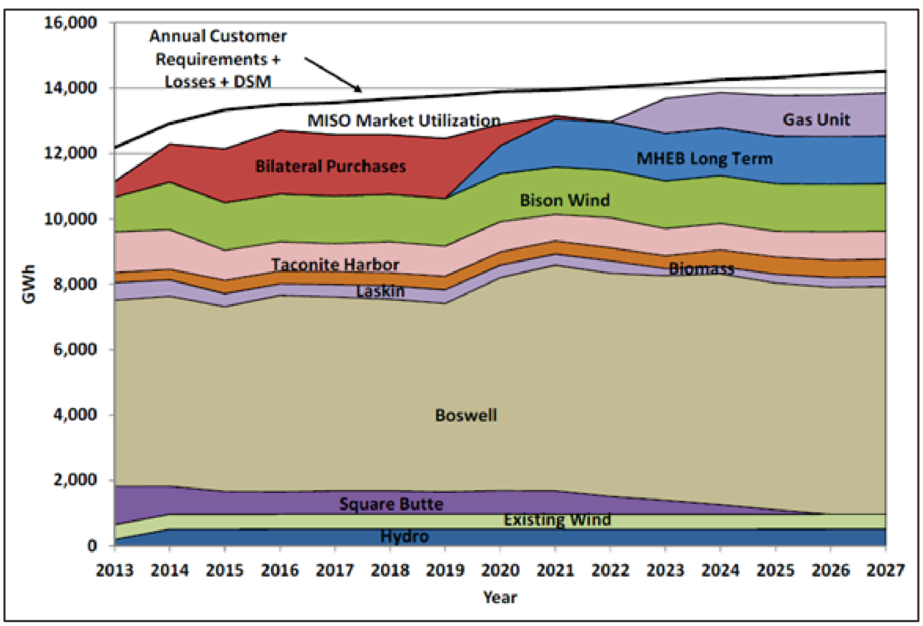

Figure 6-7: Minnesota Power Preferred Plan energy position outlook.[33]

[32] *Id.*, Figure 18, p 68.

Currently, MH and Minnesota Power have a 50 MW system participation agreement, which is expected to be extended through 2020.[34] MH and Minnesota Power also have two agreements contingent on new hydro development: a 250 MW system power sale agreement and an energy exchange agreement for wind storage. These agreements are also contingent on the development of a new interconnection between Manitoba and the US. The new long-term agreement is shown in Minnesota Power's supply projections as the top blue area in Figure 6-7.

Northern States Power

NSP, consisting of Xcel Energy subsidiary operating companies Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin, operates an integrated system covering parts of Minnesota (1.23 million customers), Wisconsin (242,000 customers), North Dakota (88,000 customers), South Dakota (85,000 customers) and Michigan (9,000 customers).[35]

Figure 6-8: Northern States Power Integrated System Service Area (dark green)[36]

[33] *Id.*, Figure 19, p 69.
[34] LCA/MH I-015.
[35] Xcel Energy, "Service Areas," http://www.xcelenergy.com/About_Us/Our_Company/Service_Areas.
[36] *Id*.

In August 2010 Xcel Energy filed an Upper Midwest Resource Plan for the five-state NSP system for the period 2011-2025, and in December 2011 filed an update to the plan.[37] The resource plan projects an energy load of about 46,000 GWh in 2014, increasing over the study period at an average annual growth rate of 0.5%. NSP is a summer peaking system. The plan projects summer net peak demand to be about 9,300 in 2014, increasing over the study period at a 0.7% average growth rate.[38]

NSP's 2010 energy supply mix was almost 20% renewable, including about 5% from contracts with MH.[39] In Xcel's proposed plan, renewable energy would supply a quarter of all energy by 2025, with MH contracts continuing to be a significant piece (see Figure 6-9).

NSP's 2011 updated plan calls for the conversion of almost 300 MW of coal-fired generation to burn natural gas for a few years before ultimately retiring in response to MATS and other regulations. NSP also plans to invest tens of millions of dollars in emission controls on the remainder of its coal fleet to meet MATS requirements.[40]

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[37]Xcel Energy, "Resource Plans," http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Resource_Plans/MN_Regulatory_Upper_Midwest_Resource_Plan_2011_-_2025.

[38] Excel Energy, "Update to the 2010 Upper Midwest Resource Plan 2011-2025," http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/2010_Resource_Plan_Update.pdf, pp 17-18.

[39] *Id.*, pp 1-18; 5-1 – 5-2.

[40] *Id.*, pp 40-47.

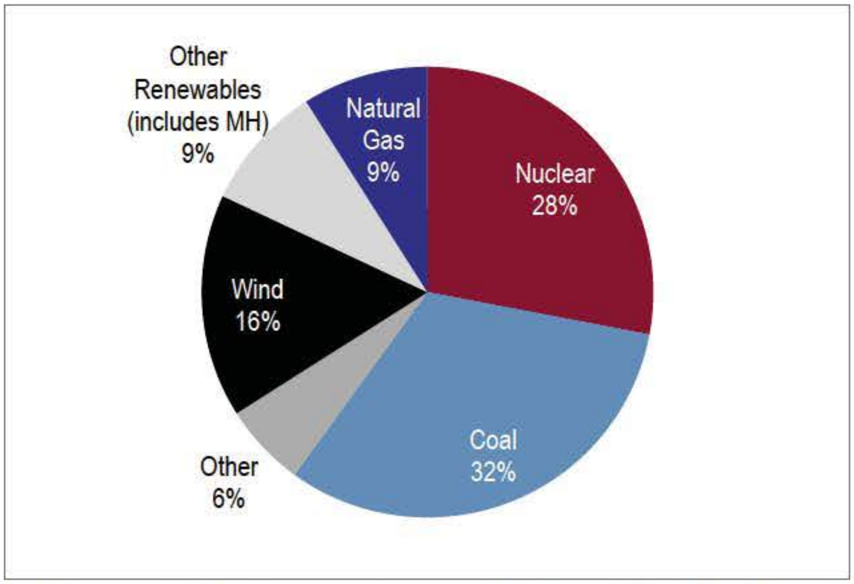

Figure 6-9: Xcel Energy 2010 Proposed Plan, Projected 2015 Northern States Power Energy Supply Mix[41]

NSP has a variety of contracts with MH. NSP and MH have a series of existing or signed seasonal diversity contracts to exchange 350 MW of capacity through 2025. NSP also has a System Participation contract that provides for the purchase of 500 MW of capacity through April 2015. NSP has signed an extension of that agreement for 375 MW in the summer and 325 MW in the winter through April 2025; an additional 125 MW (year round) extension is contingent on the addition of a major new hydro generating station.[42] The system participation contracts are for delivery of capacity and energy five days per week, 16 hours (summer) or 12 hours (winter) per day.[43] Finally, a 500 MW Energy Services Agreement provides MH with firm import transmission.[44]

[41] *Id.*, p 4-6.

[42] NFAT Submission, Appendix 9.3, pp 20-22.

[43] Xcel Energy, "Petition for Approval of Power Purchase and Diversity Exchange Agreements with Manitoba Hydro," MN PUC Docket No. E002/M-10-633, http://www.xcelenergy.com/staticfiles/xe/Regulatory/ManitobaHydroPetition_6-10-10_Public.pdf, p 7.

[44] NFAT Submission, Chapter 5, p 6.

Wisconsin Public Service

WPS, a regulated utility subsidiary of Integrys Energy Group, serves more than 440,000 electric customers in central and northeastern Wisconsin and a small part of Michigan's Upper Peninsula.

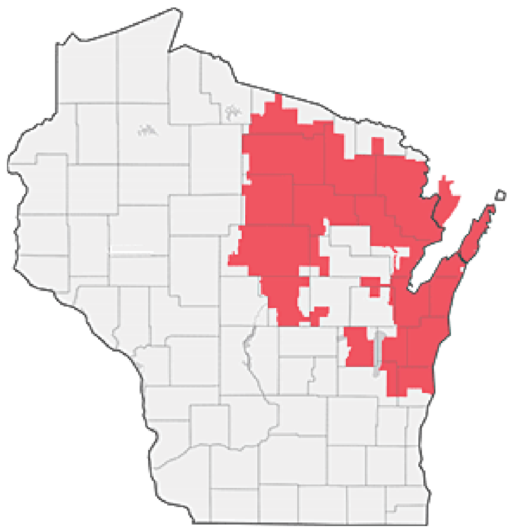

Figure 6-10: Service territory of Wisconsin Public Service[45]

According to FERC Form 1 data, WPS's 2012 system peak load was 2,347 MW. The winter peak of 1,797 MW in January was 23% lower than the summer peak. Retail sales were 10,882 GWh.[46] In WPS's most recent rate case, total gross energy requirements for the 2014 test year were projected to be almost 15,000 GWh. Almost half of those energy requirements are expected to be met with coal-fired generation. WPS also relies heavily on spot purchases in the MISO market (see Figure 6-11).

[45] Wisconsin Public Service, "Area Served," http://www.wisconsinpublicservice.com/company/area.aspx.

[46] WPS, FERC Form 1 (2012 Q4 Report), p 401b.

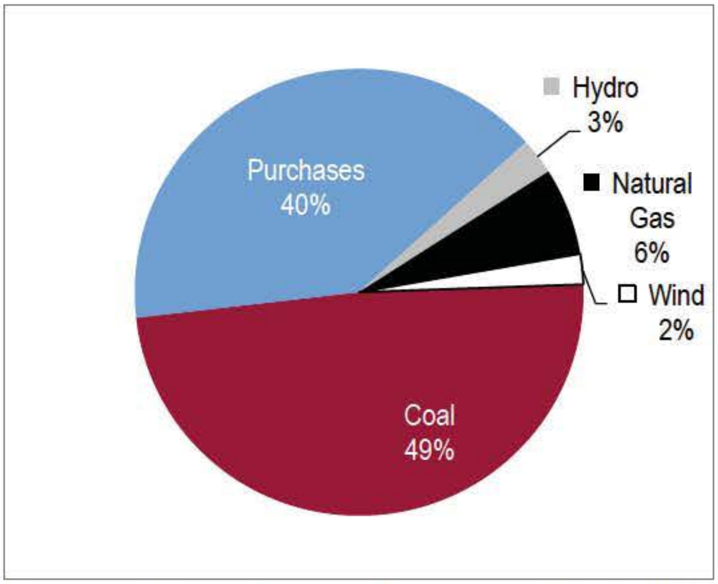

Figure 6-11: Source of Gross Energy Requirements for 2014 Test Year[47]

WPS appears to be poised to continue relying heavily on coal-fired generation into the future, despite new and expected federal emission requirements. According to the most recent biennial Wisconsin statewide SEA, WPS has recently completed or is expecting to complete major emissions control projects at its owned or co-owned coal-fired facilities with a total estimated cost of almost $1 billion.[48] WPS does not plan to retire any of its coal units before 2018.[49]

WPS has a contract with MH to receive 108 MW of energy only through May 2023.[50] WPS has also signed a 100 MW System Participation contract for June 2021 to May 2025, and a 100 MW Surplus Energy contract for June 2025 to May 2029, both contingent upon the completion of Keeyask Generating Station. WPS and MH are also in discussions to execute a new System Participation and Surplus Energy contract,

[47] WPS, 2014 Rate Case, "Summary of Test Year MWH Sources," http://www.wisconsinpublicservice.com/company/rate_case/rate_case2014_27_Rqmt_07A_Fuel.pdf.

[48] Public Service Commission of Wisconsin, Final Strategic Energy Assessment; Energy 2018," http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=176432, p 14.

[49] *Id.*, Appendix A, p 2.

[50] LCA/MH I-015.

contingent upon new hydro development and new transmission interconnections to MISO.[51]

<u>Great River Energy</u>

Great River Energy (GRE) is a wholesale electric cooperative serving 28 member distribution cooperatives in Minnesota and Wisconsin with long-term power supply and transmission service agreements. The members' service territories are shown in Figure 6-12 below. GRE's member cooperatives serve a total of about 650,000 customers.[52]

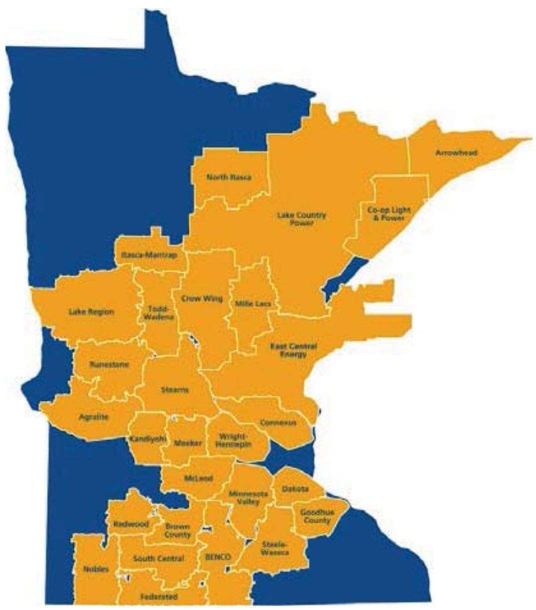

Figure 6-12: Great River Energy Members' Service Combined Service Territory[53]

GRE owns or contracts for more than 3,500 MW of generation capacity to serve a peak system demand of about 2,500 MW in 2012. GRE is a summer peaking system. Total sales to customers in 2011 were 11,650 GWh.[54] GRE is heavily reliant on coal-fired resources, which provide nearly half the capacity and 70% of energy sales. GRE owns two coal-fired plants in North Dakota with a combined 1,300 MW capacity. GRE also

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[51] NFAT Submission, Appendix 9.3, pp 21-22.

[52] Great River Energy, "Home Page," http://www.greatriverenergy.com/

[53] Great River Energy, "Resource Plan 2012-2027," MN PUC Docket No. ET2/RP-12-1114, http://www.greatriverenergy.com/makingelectricity/resourceplan/pdoc295631.pdf, p. 2.

[54] *Id.*, pp 2-3.

has a life-of-unit contract for 50% of the output from the 379 MW Genoa 3 unit in Wisconsin. Wind and hydro provide most of the remaining energy (see Figure 6-13).

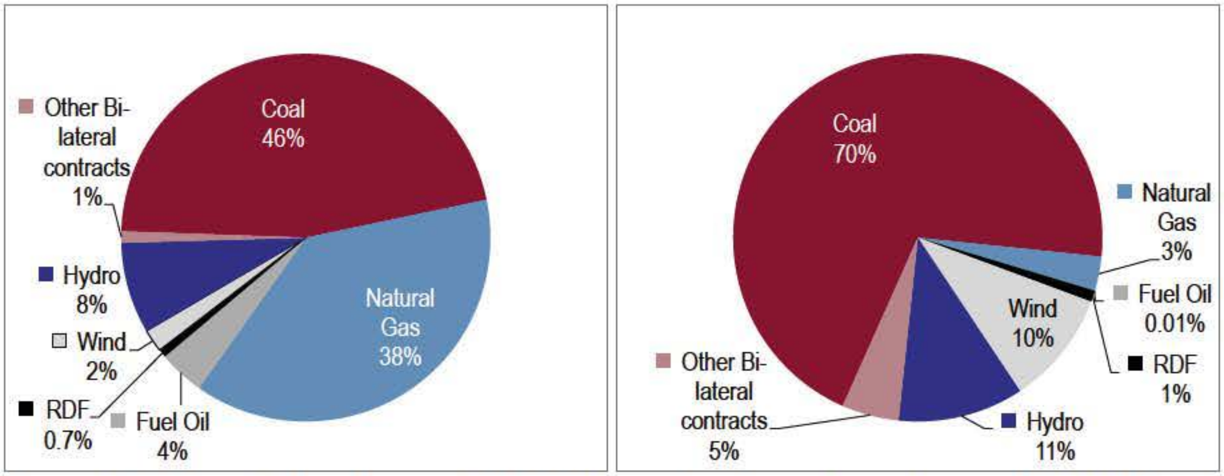

Figure 6-13: Great River Energy 2012-13 Owned and Contracted Capacity (left)[55] and 2012 Generation Mix (right)[56]

GRE filed a 15-year resource plan with the Minnesota Public Utilities Commission in November 2012. The resource plan projects 1.2% compounded annual growth in peak demand over the study period, but capacity surplus is expected to persist throughout the study period. The only anticipated resource additions are renewable credits to meet Minnesota and Wisconsin renewable requirements after 2024.[57] GRE expects to continue operating all of its owned coal units with modest emission control retrofits. Genoa 3 will require a selective non-catalytic reduction system by 2015.[58]

[55] *Id.*, p 7.

[56] Great River Energy, "Making Electricity," http://www.greatriverenergy.com/makingelectricity/.

[57] Great River Energy, "Resource Plan 2012-2027," MN PUC Docket No. ET2/RP-12-1114, http://www.greatriverenergy.com/makingelectricity/resourceplan/pdoc295631.pdf, pp 10-11.

[58] *Id.*, pp 26-27.

The Minnesota PUC rejected GRE's resource plan, however, due to questions about the load forecast and insufficient consideration of alternatives to existing resources, among other reasons.[59]

GRE has had a seasonal diversity exchange of 150 MW in place with MH since May 1995. GRE and MH have agreed to extend that agreement to 200 MW from November 2014 to April 2030.[60]

Wisconsin Public Power, Inc.

Wisconsin Public Power, Inc. (WPPI) is a regional power company serving 51 consumer-owned electric utilities with more than 200,000 customers in Wisconsin, Upper Michigan and Iowa.[61]

WPPI owns or contracts for about 850 MW of generation capacity. About 20% of owned and purchased capacity is renewable, sufficient to comply with all Wisconsin and Michigan renewable mandates.[62]

[59] Minnesota PUC, "Order Rejecting Resource Plan and Setting Future Filing Requirements," 9/26/13, Docket No. ET2/RP-12-1114, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={913ACB62-C497-42BD-BE2E-C6140B57BBC8}&documentTitle=20139-91745-01. The PUC did not require GRE to refile a revised resource plan, but rather provided directives for filing the next plan in November 2014.

[60] NFAT Submission, Appendix 9.3, p. 20 and LCA/MH I-015.

[61] WPPI, "Who We Are," http://www.wppienergy.org/whoweare.

[62] WPPI, "Renewable Resources," http://www.wppienergy.org/renewableresources.

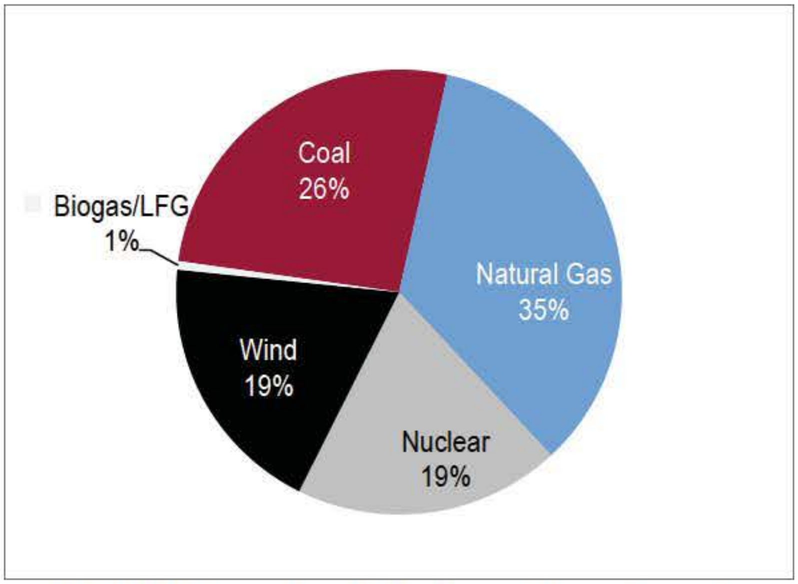

Figure 6-14: WPPI Owned and Purchased Generation Capacity[63]

WPPI does not currently have any energy or capacity contracts with MH.

Smaller Counterparties

Though the above-mentioned entities represent some of the more likely counterparties for MH due to size, location and recent contracting history, any MISO member is a potential counterparty. OTP and Minnkota Power Cooperative were involved (with NSP) in the 1970 development of the first 230 kV interconnection between MH and the US.[64] OTP is an investor-owned utility with 130,000 customers in Minnesota, North Dakota and South Dakota.[65] Minnkota is a generation and transmission cooperative serving 11 member distribution cooperatives in eastern North Dakota and northwestern Minnesota.[66]

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[63] WPPI, "Owned and Purchased Generation," http://www.wppienergy.org/ownedgeneration.

[64] Manitoba Hydro, "History and Timeline – 1970-1979, A Period of Growth and Change," http://www.hydro.mb.ca/corporate/history/hep_1970.html.

[65] OTP, "Who We Are," https://www.otpco.com/about-us/#who-we-are.

[66] Minnkota Power Cooperative, Inc., "About Us," http://www.minnkota.com/Pages/aboutus.html.

MISO-Administered Markets

In addition to the bilateral market opportunities, MH has opportunities to sell more broadly to participants through the MISO spot markets (day ahead and real time energy markets and other ancillary services markets). MISO's markets are a relatively recent development in MH's history and MISO spot market transactions have evolved over time. In 2005, MISO launched its energy trading market in which market participants submit bids and offers, which clear in the market and form the basis for MISO's locational marginal prices or LMPs.[67] (For more information about the locational nature of MISO's market see Appendix 5.2 of the NFAT Submission.) MISO began administering spot markets for ancillary services in 2009.[68] In 2013, MISO implemented changes to its resource adequacy construct and administered a new voluntary locational Planning Resource Auction, which allows market participants to buy and sell capacity for the upcoming planning year.[69] More information about each of these markets is provided below.

Energy

MISO operates a Day 2 market, where energy is purchased and sold in both day-ahead and real-time markets. These markets provide greater transparency than strictly bilateral markets, as prices are public, and this provides MH with increased opportunities to sell surplus energy.

MH transacts in the MISO market at the border between Manitoba and the US, and according to MH it "does not require US Federal Energy Regulatory Commission market based rate authority to sell energy to the MISO market as the sale does not occur in the US, but rather title to the energy transfers to MISO at the Canada-US border."[70] The power sales and purchases clear at the MH Electric Board (MHEB) node at the MHEB price.[71] Historical MHEB prices are shown in the charts below. The charts show a decline in prices in 2009, driven by declines in natural gas prices and economic

[67] MISO, "History," https://www.misoenergy.org/AboutUs/History/Pages/History.aspx.

[68] *Id.*

[69] MISO, "Resource Adequacy," https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacy.aspx.

[70] LCA/MH II-507c.

[71] LCA/MH II-506a; LCA/MH II-507a.

growth. Moreover, the Canadian and US dollar exchange rate also declined in this period.[72] The last chart also shows the historical differences in prices between the MHEB node and MISO market hub prices at locations throughout the MISO market region.

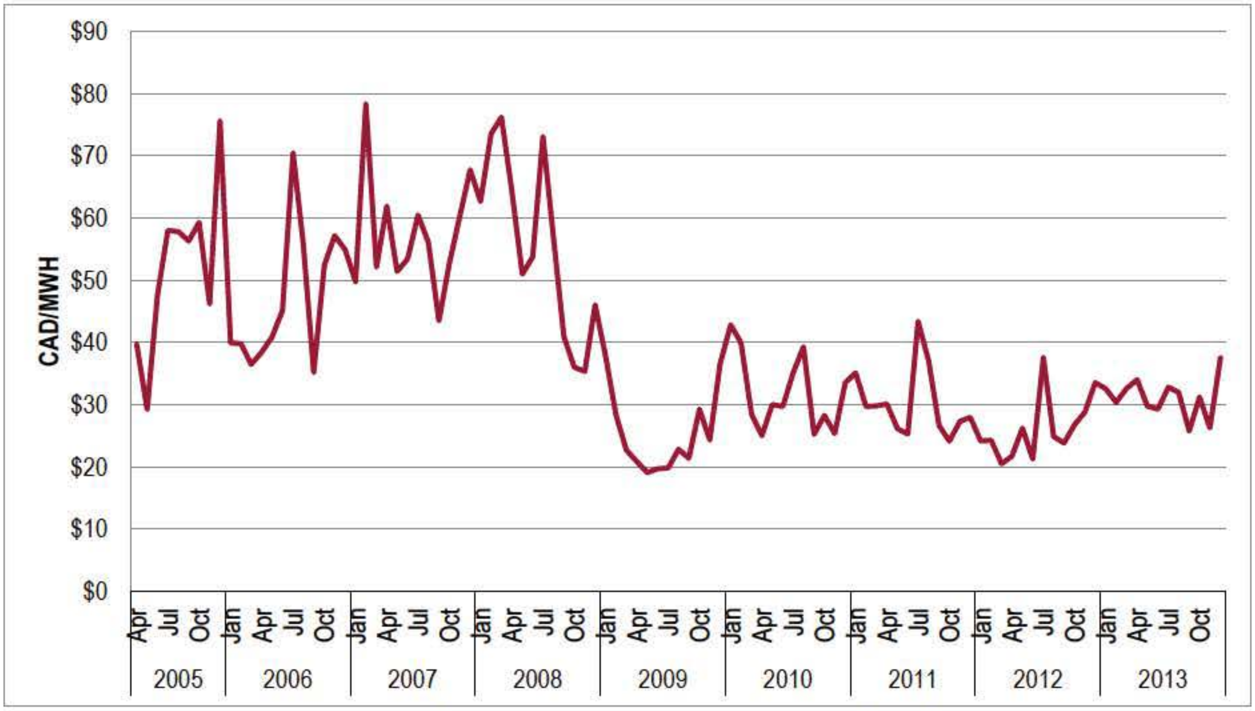

Figure 6-15: Monthly peak MHEB prices. From GlobalView data.

[72] OANDA, Currency Converter Historical Exchange Rates, www.oanda.com/currency/historical-rates/.

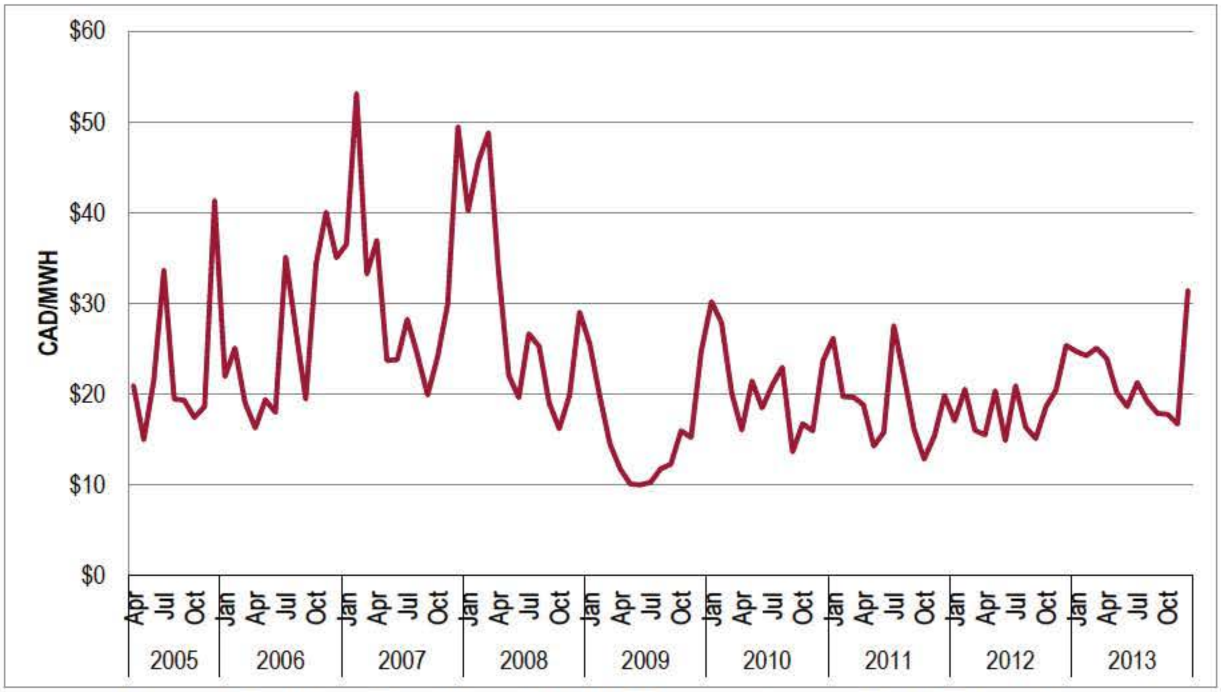

Figure 6-16: Monthly off-peak MHEB prices. From GlobalView data.

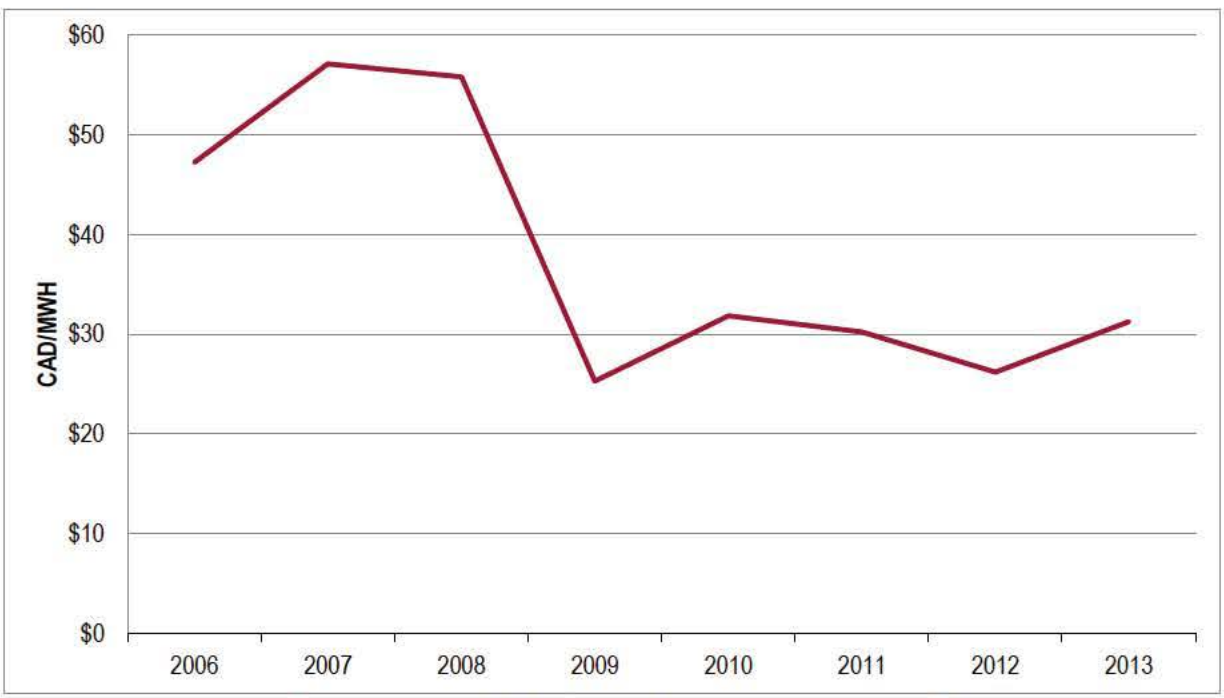

Figure 6-17: Annual peak MHEB prices. From GlobalView data.

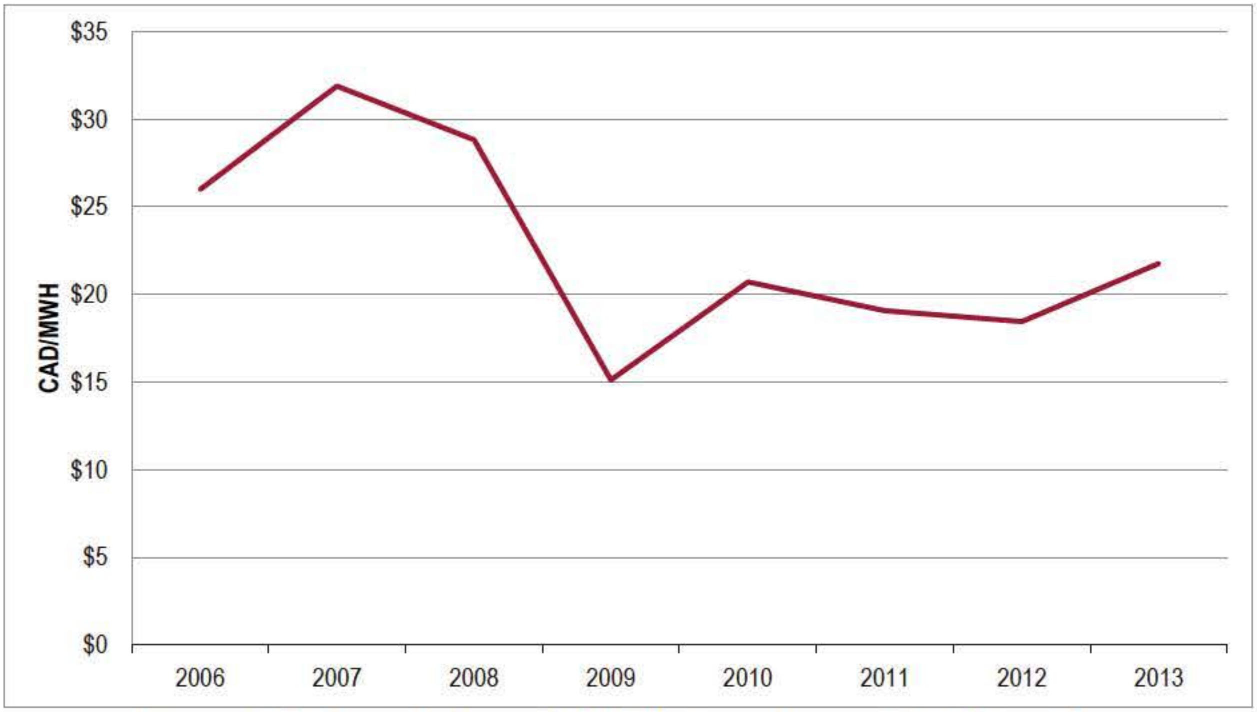

Figure 6-18: Annual off-peak MHEB prices. From GlobalView data.

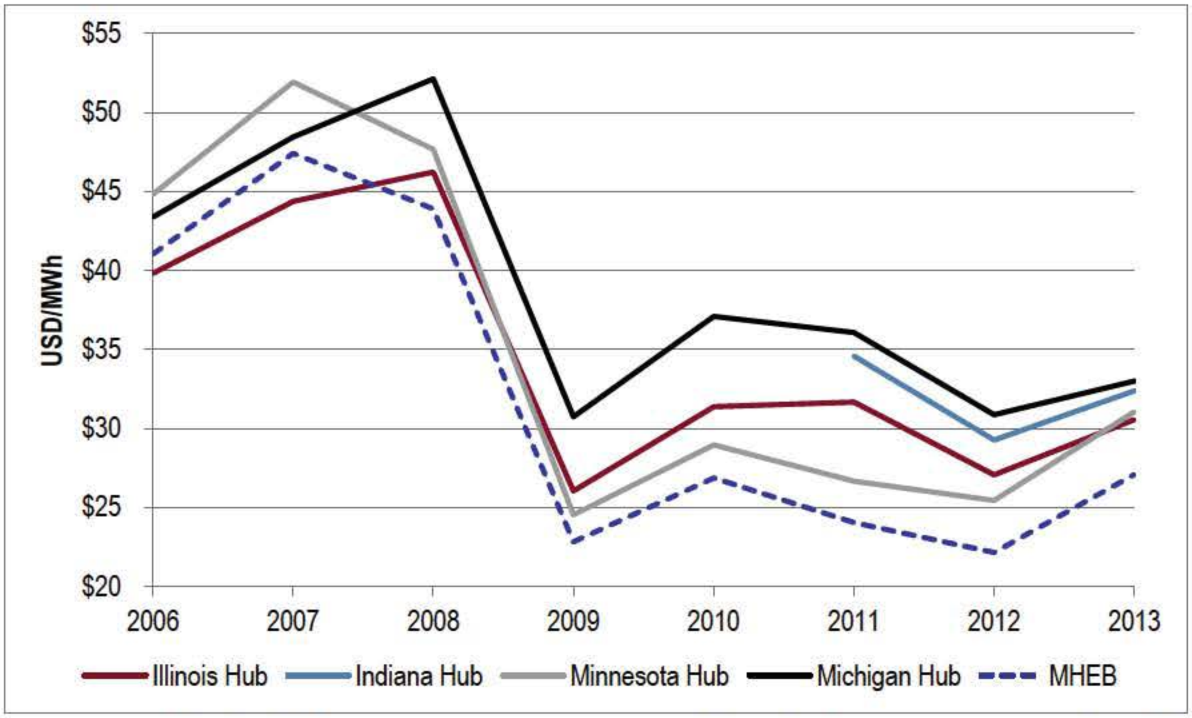

Figure 6-19: Historical MHEB prices compared to MISO hub prices from GlobalView data.

MH may participate in this market as much as it wants subject to transmission availability constraints per the following ways:

- In the day-ahead market, MH submits bids to purchase power with a price determined based on its water in storage and submits offers to sell power at a price based on the value of water in storage plus a small risk premium.[73] The amount which clears the market is sold or purchased at the MHEB clearing price.[74]
- In the real-time market, MH submits bids to purchase power and submits offers to sell power, but is unable to make the bids and offers at a specified price, rendering MH a price-taker in this market.[75] All of this power is sold or purchased at the MHEB clearing price.[76]

[73] LCA/MH II-506a; LCA/MH II-507a.

[74] *Id.*

[75] *Id.*

[76] *Id.*

- MH also has the ability to sell (although not purchase) some of its energy[77] on a day-ahead and real-time basis as an external asynchronous resource (EAR).[78] MH's resources that supply power through the high-voltage direct current transmission system are eligible to supply power as an EAR.[79] Submitting offers of energy in the real-time market as an EAR provides a limited amount of real-time price protection as MH is permitted to submit a minimum offer price for power sold under the EAR construct.[80]

MISO markets will continue to evolve over time and may continue to create new opportunities for MH to export power to the US. One important expected upcoming change involves MH's participation in MISO markets as an EAR. MISO is considering a change that would allow MH to purchase power from the grid as an EAR and use price-sensitive bids in the real-time market. These changes are expected to take effect in 2015. MISO found expanding the EAR structure to this bidirectional form would provide additional wind-hydro synergy benefits.[81]

Capacity

MISO's Resource Adequacy construct requires market participants to forecast peak load for the upcoming planning year; market participants are then required to carry sufficient generation capacity to meet this peak load plus a reserve margin.[82] MISO's capacity market is primarily a bilateral market,[83] although, as indicated earlier, in 2013 MISO implemented an annual zonal Planning Resource Auction, where market participants can buy and sell capacity that has not been sold on a bilateral basis.

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[77] Manitoba Hydro may also sell ancillary services as an EAR.

[78] LCA/MH II-506b; LCA/MH II-507b.

[79] NFAT Submission, Appendix 5.2, p. 2.

[80] LCA/MH II-507b.

[81] For more on the expansion of Manitoba Hydro's EAR capability, see MISO's "Manitoba Hydro Wind Synergy Study-Final Report," pp. 2-3, at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Planning%20Materials/Manitoba%20Hydro%20Wind%20Synergy%20TRG/Manitoba%20Hydro%20Wind%20Synergy%20Study%20Final%20Report.pdf.

[82] NFAT Submission, Appendix 5.2, p. 4.

[83] *Id.*

Until June 2013, all of MH's capacity sales were made on a bilateral basis.[84] However, going forward, MH anticipates it will continue to sell surplus capacity through long-term bilateral agreements, but intends to offer any surplus generation not sold through long-term agreements into the MISO Planning Resource Auction.[85]

Currently, all of MH's generation units except Brandon Unit 5—which is restricted to emergency operation only—are qualified to supply capacity into the MISO market, and after the assumed retirement of this unit in 2019/20, MH assumes all generation will qualify to sell capacity into MISO.[86]

Ancillary Services

MH participates in MISO ancillary services markets.[87] MISO ancillary services markets began in 2009, and MH's total revenues from these sales have been relatively small, as shown in the table below. As with MISO's energy markets, units connected to the high-voltage direct current transmission system are also capable of selling ancillary services as an EAR.

Ancillary Service Market Revenue (CAD $)	
2008/09	1,326,839
2009/10	2,012,464
2010/11	1,575,051
2011/12	701,784
2012/13	644,403

Figure 6-20: Manitoba Hydro Historical MISO Ancillary Services Export Revenues.[88]

84 LCA/MH I-381.

85 LCA/MH I-385.

86 LCA/MH I-382.

87 NFAT Submission, Chapter 5, p. 21:9-15.

88 LCA/MH I-375.

MISO Region Summary

MH's historical reliance on bilateral contracting with neighboring, vertically-integrated utilities will likely continue to be the primary target market for MH's firm energy and capacity sales. The advent of the MISO market in 2005 and the maturation and development of that market over time has provided added energy spot market and other market opportunities, such as through the ancillary services market, which began in 2009, and the new annual Planning Resource Auction for capacity. The MISO-administered markets provide the added advantage of greater market price transparency, benefits which carry over into the bilateral market as they assist in the negotiation of bilateral contracts. Further developments in MISO's markets will likely continue to create more opportunities for MH to export energy and other services. As an example, expected developments in MH's participation in MISO markets as an EAR will likely provide real-time market import price protection and enhance MH's ability to use its hydro storage system to better integrate wind power generation into the region.

B. Saskatchewan

Saskatchewan, which like Manitoba is in the Eastern Interconnection, has a purely bilateral wholesale market, and the Crown-owned, vertically-integrated utility SaskPower has the exclusive right and obligation to supply electricity to the province, except the cities of Swift Current and most of the city of Saskatoon.[89] SaskPower operates a fleet of generation assets with a mix of hydro and thermal either owned by SaskPower or several independent power producers all shown in the map below.[90] In 2012, SaskPower had 4,104 MW of power generation available to serve a peak load of 3,314 MW.[91] To meet new load growth and replace aging infrastructure, SaskPower plans to add 1,300 MW of new generation to the grid by 2017.[92]

SaskPower also operates Saskatchewan's transmission system, also shown in the map below. Access to transmission is administered through SaskPower's OATT.[93]

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[89] NFAT Submission, Chapter 5, p. 51:20-24; Swift Current is a small city with a population of approximately 16,000 people and purchases wholesale power from SaskPower; For more on Swift Current, see http://www.swiftcurrent.ca/city_hall.php?name=Sections&op=viewarticle&artid=136; Saskatoon Light and Power services approximately 59,000 customers and also purchases wholesale power form SaskPower; For more on Saskatoon Light and Power see http://www.saskatoon.ca/DEPARTMENTS/Utility%20Services/Saskatoon%20Light%20and%20Power/Pages/default.aspx.

[90] SaskPower also owns and operates the Saskatchewan transmission system and is a retail provider of electricity.

[91] SaskPower, "SaskPower Annual Report 2012," http://www.saskpower.com/wp-content/uploads/2012_saskpower_annual_report.pdf, p.3.

[92] SaskPower, "It takes Power to Grow – Chapter 1," http://www.saskpower.com/our-power-future/it-takes-power-chapter-1/.

[93] SaskPower, OATT, http://www.saskpower.com/wp-content/uploads/open_access_transmission_tariff.pdf.

Figure 6-21: SaskPower System Map.[94]

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[94]SaskPower,
http://www.saskpower.com/about-us/our-company-and-strategic-direction/our-facilities-and-system-map/.

Saskatchewan meets a significant amount of its electricity demand with coal-fired generation fueled with lignite coal mined within the province.[95] To meet environmental regulations, SaskPower is pursuing carbon capture and sequestration technology. It is building a carbon capture and storage demonstration project at the Boundary Dam Power Station.[96] However, in December 2013, the Saskatchewan Environmental Society published a report urging SaskPower to close its coal power plants and replace them with renewable power.[97]

Manitoba and SaskPower have signed a memorandum of understanding to explore specific initiatives, including new power sales and transmission interconnections.[98] More recently, Manitoba and SaskPower signed a 25 MW term sheet from 2015-2022 and a signed agreement is expected by mid-2014.[99] MH characterizes the likelihood that such an arrangement will be finalized as "very high."[100]

C. Ontario

Ontario has both a bilateral market and a structured real-time energy clearing market operated by the Independent Electricity System Operator (IESO). MH has been an active participant in the IESO since its inception in 2002.[101] The IESO market establishes the Hourly Ontario Energy Price (HOEP), a price paid by wholesale customers throughout the province.[102] In the past year, average HOEPs have typically been lower

[95] Johnstone, Bruce, "Sherritt sells coal assets, including Sask. mines, for $946M," *Leader-Post,* 26 December 2013, http://www.leaderpost.com/business/Sherritt+sells+coal+assets+including+Sask+mines+946M/9323829/story.html; "Coal," *Encyclopedia of Saskatchewan,* http://esask.uregina.ca/entry/coal.html.

[96] SaskPower, "Annual Report 2012," http://www.saskpower.com/wp-content/uploads/2012_saskpower_annual_report.pdf, p. 31.

[97] Larson, Scott, "Close coal-fired plants, SES says," *The StarPhoenix,* http://www.thestarphoenix.com/technology/Close+coal+fired+plants+says/9299465/story.html.

[98] NFAT Submission, Chapter 5, p. 52:16-20.

[99] LCA/MH I-034.

[100] *Id.*

[101] NFAT Submission, Chapter 5, p. 49:6-7.

[102] IESO, "Energy Market Overview," http://www.ieso.ca/imoweb/mktOverview/mktOverview.asp; The IESO also determines Five-Minute Market Clearing Prices paid to dispatchable load and

than wholesale prices in neighboring control areas, including MISO, as shown in the figure below.

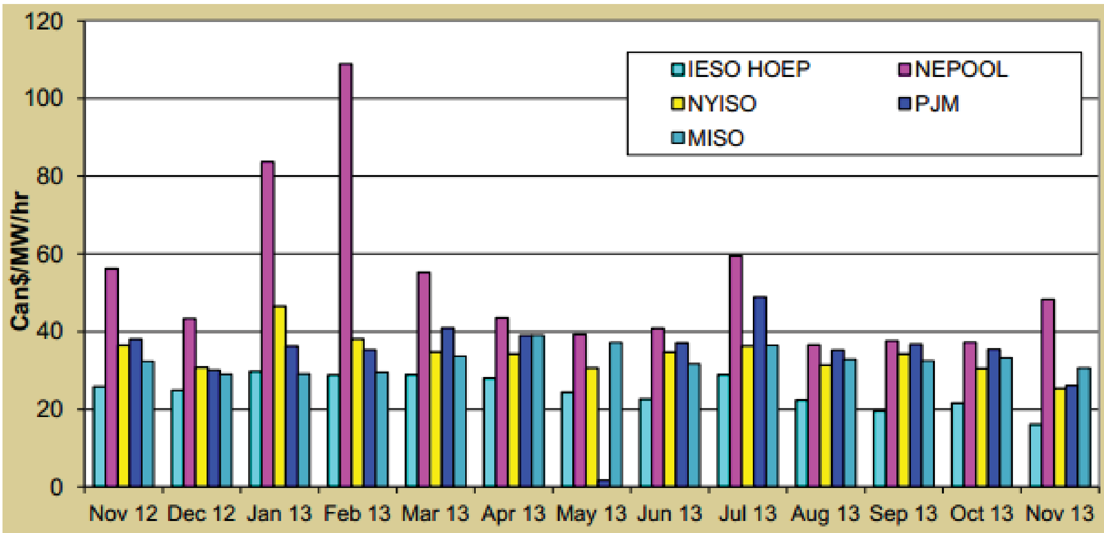

Figure 6-22: Comparison of IESO HOEP and neighboring control area prices.[103]

As for the bilateral market, MH is interconnected with Northwestern Ontario, shown in the map below.

generation and prices for Operating Reserves. See http://www.ieso.ca/imoweb/pubs/marketReports/monthly/2013nov.pdf.

[103] IESO, "Monthly Market Report," November 2013, p. 14, http://www.ieso.ca/imoweb/pubs/marketReports/monthly/2013nov.pdf.

Figure 6-23: Transmission map of Northwest Ontario (West of Wawa, Ontario)[104]

As of 2010, the Northwest Ontario region had 800 MW of hydro generation, most from plants under 100 MW.[105] There are also two major thermal stations: Thunder Bay

[104]Hydro One, http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2010-0002/A/A-06-01%20Transmission%20System%20Maps.pdf.

[105] Ontario Energy Board, http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/EWT_OPA%20_Report_20110630.pdf, p. 8; http://www.opg.com/power/hydro/northwest_plant_group/; Atlantic Power Corporation, "Assets," http://www.atlanticpower.com/assets.aspx; Brookfield Renewable Power, "Wawa Hydro Operations,"

Generating Station (306 MW)[106] and Atikokan Generating Station (230 MW).[107] In addition, the 98.9 MW Greenwich Windfarm went into service in 2011 in the District of Thunder Bay.[108]

Given the region's reliance on hydro generation, when MH has water to generate power for export, the Ontario region will also likely have excess water and so be less interested in importing from Manitoba at that time. To increase the reliability of the Northwest region, the province is planning to increase the transfer capability of the East-West tie between Northwest and Northeast Ontario from about 350 MW to 650 MW to help Northwest Ontario meet demand in low water years.[109]

Although the region is large, covering 60% of Ontario's land area, it is home to only two percent of Ontario's total population, with half of that population residing in the City of Thunder Bay.[110] Currently, the region has ample generating resources to meet its needs, since the region has a peak load of about 750 MW.[111] Peak load is expected to grow to over 900 MW by 2030 driven by growth in the mining sector.[112] Atikokan and Thunder Bay Generating Stations were both coal-fired, and the province of Ontario has a plan to

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http://www.brookfieldpower.com/_Global/5/documents/relatedlinks/721.pdf; H2O Power, "Locations," http://www.h2opower.ca/locations.

[106] Ontario Power Generation, "Thunder Bay Generating Station," http://www.opg.com/power/thermal/thunderbay.asp.

[107] Ontario Power Generation, "Atikokan Generating Station," http://www.opg.com/power/thermal/atikokan.asp.

[108] Ontario Power Authority, "Greenwich Windfarm (98.9 MW) – District of Thunder Bay," http://www.powerauthority.on.ca/wind-power/greenwich-windfarm-989-mw-district-thunder-bay.

[109] Ontario Energy Board, "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion," http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/EWT_OPA%20_Report_20110630.pdf.

[110] Ontario Power Authority, "Northwest Ontario," http://www.powerauthority.on.ca/power-planning/regional-planning/northwest-ontario.

[111] Ontario Power Authority, "Ontario Electricity Demand, 2012 Annual Long-term Outlook," http://www.powerauthority.on.ca/sites/default/files/news/Q2-2012LoadForecast.pdf, p. 50.

[112] *Id.*

eliminate all coal-fired generation by 2014.[113] Atikokan Generating Station is being converted to burn biomass.[114] Thunder Bay Generating Station was under consideration for a conversion to natural gas, but that review has stopped, and it may retire in the future.[115]

If the region were to require new supply in the future, current Ontario policy favors building new resources within the province instead of importing generation. Ontario has been and continues to procure new generation and is funding this investment through a "global adjustment" charge to consumers, which is set to reflect the difference between the market price and:[116]

- "The regulated rates paid to Ontario Power Generation's nuclear and hydroelectric baseload generating stations;
- Payments made to suppliers that have been awarded contracts through the Ontario Power Authority such as new gas-fired facilities, renewable facilities (like wind farms) and demand response programs; and
- Contracted rates administered by the Ontario Electricity Financial Corporation paid to existing generators."

To date, MH is not eligible to receive revenue from global adjustment charges since its generation assets are located outside of Ontario.[117]

MH is not actively pursuing new long-term export sales to Ontario for the following reasons:[118]

- Northwestern Ontario already has ample generation.

[113] Ontario Ministry of Energy, "Making Choices – Reviewing Ontario's Long-Term Energy Plan," http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2013/LTEP.pdf, p. 5.

[114] Ontario Power Generation, "Atikokan Generating Station," http://www.opg.com/power/thermal/atikokan.asp.

[115] Ontario Power Generation, "Thunder Bay Generating Station," http://www.opg.com/power/thermal/thunderbay.asp.

[116] IESO, "Global Adjustment," https://www.ieso.ca/imoweb/siteshared/electricity_bill.asp.

[117] NFAT Submission, Chapter 5, p. 51:12-17.

[118] *Id.*, pp. 50:14-51:17.

- Pursuing exports beyond Northwestern Ontario into Toronto would require substantial and costly transmission.
- Current Ontario policy favors building new resources within the province as opposed to new imports.

As mentioned earlier, Northwestern Ontario is expanding transmission ties to the rest of the province to secure more reliable supply; however, this is done to support operations in low water years. MH would have relatively little surplus power to sell in low water years.

D. Alberta

Alberta has a larger market than either Saskatchewan or Northwest Ontario, with 13,898 MW of installed generating capacity and a 2012 peak load of 10,599 MW.[119] The installed generating capacity is dominated by thermal resources as shown in the figure below.

[119] Government of Alberta, "Energy – Electricity Statistics," http://www.energy.gov.ab.ca/Electricity/682.asp.

Generating Capacity Type	Amount (MW)
Coal	5,690
Gas	5,683
Hydro	900
Wind	1,113
Biomass	414
Waste Heat*	86
Fuel Oil	12
Subtotal	13,898
Interconnections Capacity	**Amount (MW)**
British Columbia	750
Saskatchewan	150
Subtotal	900
Grand Total	14,798

*Waste heat generation is a system that produces electricity from a heat source that is a by-product of an existing industrial process, the heat that would have been otherwise wasted.

Figure 6-24: Alberta installed generating capacity and interconnections.[120]

The Alberta Electric System Operator (AESO) operates an energy-only, real-time market and an ancillary services market.[121] Alberta power pool prices during peak hours have remained higher than in other markets such as MISO despite declines in natural gas prices. This is in part due to increasing demand in the region. All of this is shown in the figure below.

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Average Pool Price ($/MWh)	73.41	64.03	85.35	101.41	84.37	112.97	58.04	62.99	102.22	84.72
AECO NG Price ($/GJ)	$6.30	$6.19	$8.27	$6.17	$6.10	$7.73	$3.76	$3.79	$3.44	$2.27
Total Energy (GWh)	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723	73,600	75,574

Figure 6-25: AESO average peak power prices, natural gas prices, and total energy demand.[122]

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120 *Id.*

121 NFAT Submission, Chapter 5, p. 52:23-25.

122 AESO, "2012 Annual Market Statistics," http://www.aeso.ca/downloads/AESO_2012_Market_Stats.pdf, pp. 2, 6.

MH is not actively pursuing sales to Alberta, as Alberta's interconnection with Saskatchewan is only 150 MW, and since Minneapolis is closer to Manitoba than Calgary, transmission costs would be lower to expand sales to the US as opposed to Alberta.[123] Alberta is also in the Western Interconnect, requiring converter stations to interconnect with the Eastern Interconnect at the border with Saskatchewan, such as the existing McNeil Converter Station.[124]

E. Export Markets Summary

In general, MH has presented a reasonable portrayal of its export market opportunities in the NFAT Submission. MH's primary export market is likely to continue to be the US, specifically the MISO region. The MISO region provides export opportunities through both bilateral contracts with utilities in the region and through formal markets administered by MISO. Historically, bilateral contracts have been MH's primary method for exporting power to the US, and this is likely to remain the case for the foreseeable future. However, starting in 2005, the MISO-administered markets have created new opportunities for spot market trading and have created increased price transparency. These market benefits are likely to continue to increase as the MISO-administered markets evolve over time.

MH's primary export market opportunity to other Canadian provinces is Saskatchewan, which has a purely bilateral market. It appears MH is making reasonable efforts to expand exports to this region through negotiations with SaskPower, which is the largest utility in the province.

Significant expansion of exports to Ontario or Alberta would require substantial changes to the market. MH participates in the IESO-administered energy spot market in Ontario, but this market has lower average prices than other market regions, including MISO, making it generally less attractive for spot market sales. A bilateral agreement for power export to Northwest Ontario is currently hindered by Northwest Ontario's

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[123] NFAT Submission, Chapter 5, p. 53:14-19.

[124] AESO, "307 Alberta-Saskatchewan Interconnection Transfer Limits," http://www.aeso.ca/downloads/2011-03-17_OPP_307.pdf.

policy to diversify its portfolio and reduce reliance on hydro power, as well as policies favoring in-province generation throughout Ontario. Ontario's policies favoring in-province generation also hinder MH's ability to make a new major bilateral agreement to sell power to Southern Ontario. Such a sale would also require greater transmission access to the Toronto area, which is a long distance from Manitoba. AESO operates a spot market in Alberta, which currently has prices that indicate Alberta would be an attractive market for MH. However, new transmission investment would be required to expand MH's access to Alberta, which is also a long distance from Manitoba.

IV. Critique of Manitoba Hydro Export Market Modeling

In order to properly evaluate the benefits of the Preferred Development Plan or any generation resource plan, MH must estimate the value of power exports. Exports are modeled in a number of ways in MH's planning, both with and without using MH's long-term planning model, SPLASH. SPLASH optimizes the dispatch of MH's hydro and thermal system over a 35-year planning horizon subject to various transmission and operating constraints. (For more details on SPLASH, see Appendix 9.2 in the NFAT Submission.) Fundamentally, exports fall into one of two categories: firm or opportunity sales. Each of these types of sales is discussed below, along with a description of MH's export price forecasting methodology.

A. Types of Sales

Firm Sales

MH models two types of firm sales: sales from long-term contracts and "non-committed" firm sales.

The revenues from existing and planned contractual agreements for long-term firm sales are estimated outside the SPLASH model. For more on how MH modeled these contracts, see Technical Appendix 7B: Export Contracts (to be filed at a later date).

MH also models "non-committed" firm sales, defined as sales of excess dependable hydro-electric energy assumed to be sold through long-term contracts but for which no contract or term sheet yet exists. Dependable energy refers to the amount of energy MH can generate during the worst drought year on record. For more about how dependable energy is estimated, see Technical Appendix 1: Resource Planning. These sales are for the peak 5x16 period and are priced at a premium price using the long-term dependable export price forecast discussed more below.[125] They occur throughout the 35-year detailed modeling period as long as excess dependable hydro-electric energy exists. New non-hydro generation, such as natural gas generation, is not assumed to be sold as a "non-committed" firm sale, but is only available for opportunity export sales. The underlying assumptions are that a) all hydro-electric dependable energy can be sold on a firm basis without jeopardizing system reliability as long as long-term firm transmission service is available; and that b) potential counterparties are interested in purchasing hydro generation far more than thermal generation.

Opportunity Sales

Opportunity sales are used to model all other exports, i.e. exports that are not long-term firm sales of dependable energy. This includes medium-term and spot market sales. MH's SPLASH model estimates the monthly exports of peak and off-peak opportunity energy. Although the focus of this Technical Appendix is on export markets and export modeling, SPLASH models opportunity purchases in a similar fashion as described below.

The market pricing for the opportunity purchases and sales in each year is represented using the annual average market price forecast, disaggregated into monthly subperiods using an assumed pricing relationship as discussed below. The monthly subperiod pricing is represented using a step function, where blocks of energy at a given price represent "steps" in the function.[126] For exports, prices decline as the volume of energy sold increases and vice versa for imports.[127]

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[125] NFAT Submission, Appendix 9.3, pp. 11, 88.

[126] Kubursi, Atif and Magee, Lonnie, "Manitoba Hydro Risks: an Independent Review", (KM Report), Figure 3.13, p. 87.

[127] *Id.*

Each block of energy is assigned a price using the following formula:

Block Price = Annual Price * Market Price Coefficient

Annual prices derive from the consensus price forecast described in the next section. [redacted][128] The combination of [redacted] accounts for additional revenue beyond the day-ahead energy market, such as from medium-term sales within the one-year time frame, including firm energy and capacity sales, forward energy sales and other sources of revenue.[129] According to a confidential presentation MH provided to LCA,[130] the subperiod market price coefficients for the NFAT analysis were determined using historical data analysis as follows:

1) [redacted]
2) Daily average prices for each period are grouped by calendar month and plotted as a cumulative probability curve. An example for April 2011 is shown below.

[128] CONFIDENTIAL PUB/MH I-031e.

[129] *Id.*

[130] The description of the SPLASH opportunity market is found in SP-025 "NFAT Confidential Market Coefficients in SPLASH."

[redacted]

CONFIDENTIAL Figure 6-26: April 2011 MISO price distribution. Each dot represents an average daily on peak price at the MHEB.

3) The cumulative probability curves are transformed into price duration curves through normalization to the tie-line capacity for each period. Tie-line capacity assumptions are listed below.[131] The curves are divided into segments equal to the number of days in the month for the given period, rounded to the nearest MW for computational ease. An example, also for April 2011 is shown below.
   a. [redacted]
   b. [redacted]
   c. [redacted]
   d. [redacted]

[131] These do not incorporate added tie-line capacity from potential new interconnections. The additional capacity from new interconnections are 750 MW of additional export and import capability for the 750 MW interconnection and 250 MW of export and 50 MW of import capability for the 250 MW interconnection. See NFAT Submission, Chapter 8, Table 8.2, p. 22.

[redacted]

CONFIDENTIAL Figure 6-27. Price duration curve for April 2011 peak exports.

4) Each price curve for each month is separated in bins or blocks of various sizes, and an average price is determined for each block. There are different numbers of blocks and block sizes for each market as listed below along with an example curve.
   a. [redacted]
   b. [redacted]
   c. [redacted]
   d. [redacted]

[redacted]

CONFIDENTIAL Figure 6-28. Example April 2011 price duration curve divided into [redacted] blocks.

5) The price forecast is based on a [redacted] period, while SPLASH uses a [redacted] period, so steps 1-4 are repeated for the [redacted] period.
6) Market price coefficients for each block each month of the historical period are calculated for the [redacted] period using the following formula (monthly shaping factor is used to convert between annual and monthly price):

   [redacted]
7) Through examination of the historical data, [redacted] [redacted] were discarded, and a final average set of coefficients were calculated based on equal weightings of coefficients between the [redacted]

The final coefficients are directly input into the SPLASH model and applied to the tie-line capacity available after firm sales are removed. This is shown in the figure below. The figure refers to exportable surplus or the amount of power available to be marketed for long-term sales.[132] As discussed previously, long-term sales are modeled either based on specific existing or proposed contract terms or as "non-committed" firm sales.

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132 NFAT Submission, Appendix 4.2, p. 6.

[redacted]

[redacted]

CONFIDENTIAL Figure 6-29: Example of SPLASH opportunity export market for October 2027 peak period for the Preferred Development Plan and reference price scenario.

B. MISO Market Price Forecast

MH regularly hires multiple independent consultants to provide a forecast of annual peak and off-peak MISO prices at the MINN Hub. The consultants also separately forecast MISO capacity prices and provide outlooks of carbon and other emissions prices. MH aggregates these forecasts into a "consensus price forecast."[133]

Three different price forecasts were created prior to the NFAT Submission analysis, with two such forecasts actually used in the SPLASH modeling: an adjusted 2012/2013 price forecast (2012 Adjusted Forecast) was used for the analysis presented in Chapters 9 and 10 of the NFAT Submission, and a 2013/2014 price forecast was used for the 2013 update analysis in Chapter 12.[134] The specifics of the processes used to create these forecasts varied between the two.

<u>2012/2013 Price Forecast</u>

The original 2012/2013 price forecast was an average of 35-year forecasts from five consultants:[135] [redacted][136]

<u>2012 Adjusted Forecast</u>[137]

The 2012 Adjusted Forecast was the forecast actually used in the NFAT submission analysis (for Chapters 9 and 10). The original 2012/2013 price forecast had to be adjusted for two primary reasons: a) by late 2012 it was apparent that the long-term outlook for electricity prices had lowered compared to the original forecast prepared in early 2012 and b) the electricity price forecast needed to be consistent with the corporate gas price forecast, which had relied upon a different set of consultants.[138]

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[133] NFAT Submission Appendix 9.3, p. 8.

[134] *Id.*, p. 12.

[135] *Id.*, p. 11.

[136] SPS-007 NFAT Confidential Sept 24 2013 Price Forecast Process.

[137] For the adjustment see SP-010 2012 Adjusted Electricity Price Forecast.

[138] SPS-007 NFAT Confidential Sept 24 2013 Price Forecast Process.

The figure below shows the difference between the Energy Price Outlook (EPO) gas price forecast and the Electricity Export Price Forecast (EEPF) gas price forecast, which were both consensus price forecasts, but using different consultants. MH ultimately wanted the electricity price forecast to be consistent with the EPO gas price forecast. [redacted][139]

[redacted]

CONFIDENTIAL Figure 6-30. Comparison of reference consensus Henry Hub Natural Gas price forecasts.[140]

At the end of December 2012, the consultants were also polled and confirmed their latest price outlooks were about 8% lower than the consultants' 2012/2013 outlooks from earlier, but they reported very little changes to the carbon policy and pricing outlooks.[141]

To adjust the electricity price forecast, MH first adjusted the forecast for congestion and losses between MINN Hub and MHEB based on the results of historical price data

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[139] SP-010 2012 Adjusted Electricity Price Forecast.

[140] *Id.*

[141] NFAT Submission, Appendix 9.3, p. 12.

analysis.[142] Peak energy prices are [redacted] and off-peak energy prices are [redacted].[143] MH then performed a linear regression analysis to determine the relationship between natural gas and carbon prices and electricity market prices. It used the low, reference, and high EEPF consensus forecasts to perform the regression. The results were as follows:[144]

[redacted]

Then, using the EPO natural gas price forecast and the EEPF carbon price forecast along with the regression relationship,[145] MH calculated the 2012 Adjusted electricity price forecast for the low, reference, and high scenarios.[146] A comparison of the two forecasts is shown below along with the final adjusted forecast with high, reference, and low cases.

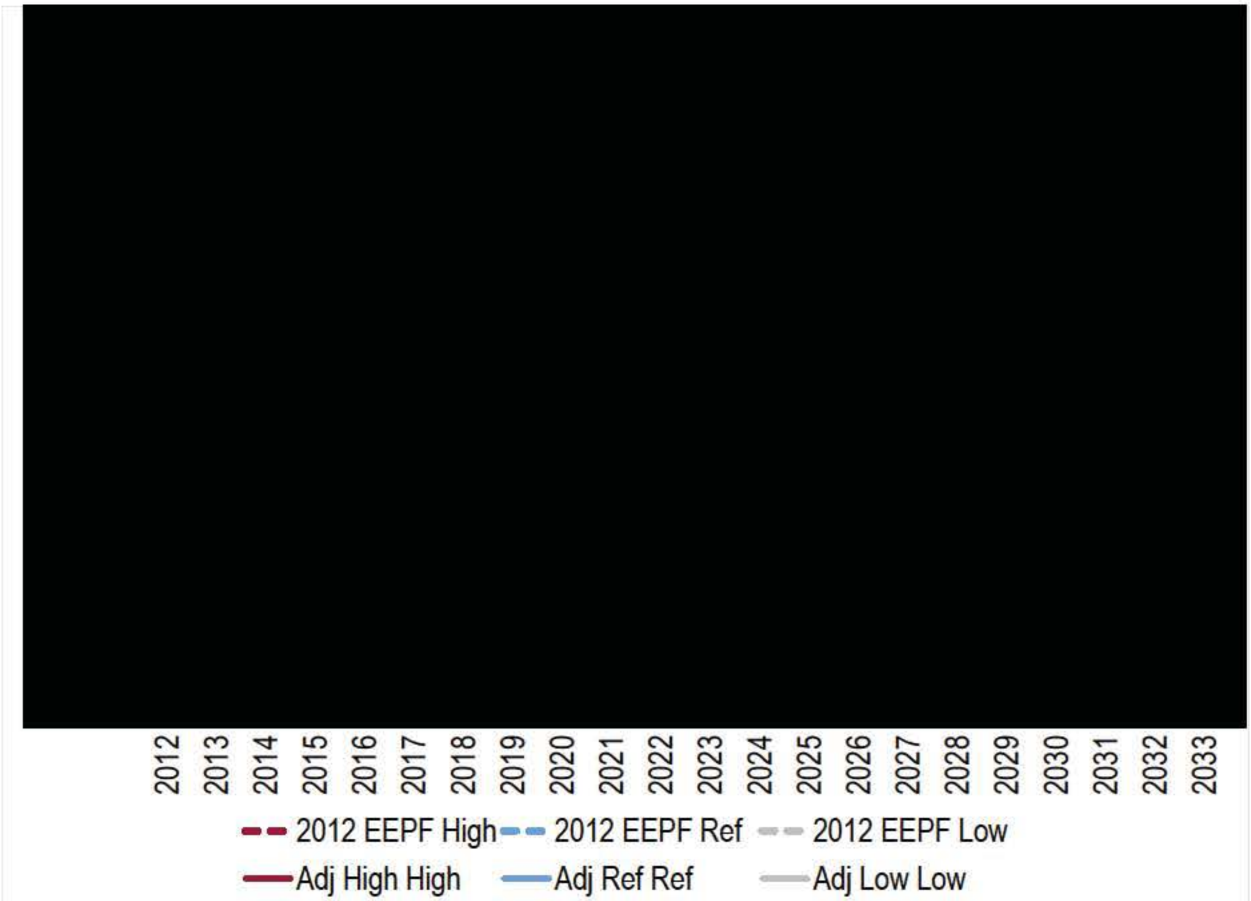
[142] *Id.*, p. 9.

[143] Sample data from 2010 and 2011 is provided in SP-059.

[144] CONFIDENTIAL PUB/MH I-160.

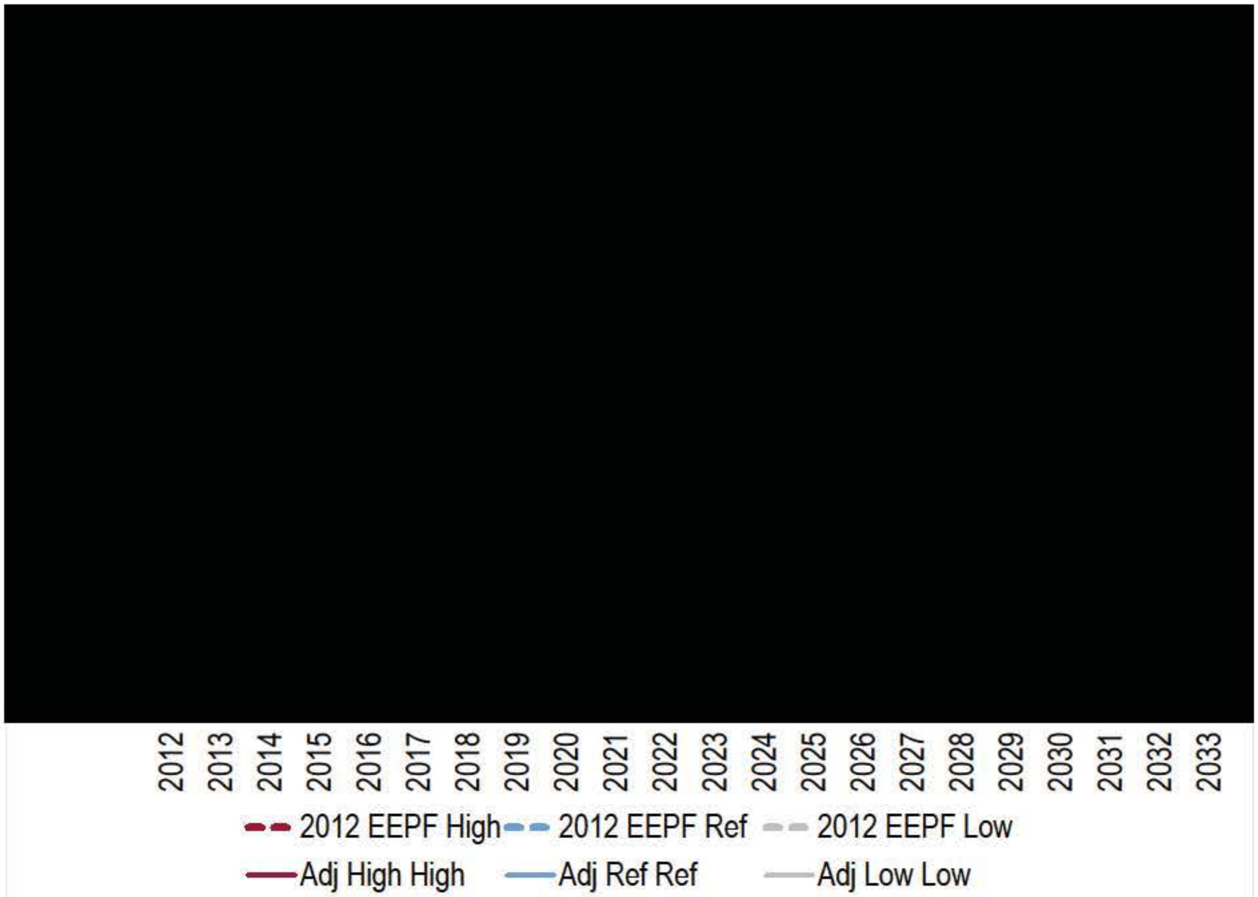
[145] Manitoba Hydro also adjusted the low carbon price forecast [redacted].

[146] SP-010 2012 Adjusted Electricity Price Forecast.



CONFIDENTIAL Figure 6-31. Comparison of original and 2012 Adjusted peak MISO electricity price forecasts at MHEB.[147]

147 *Id.*



CONFIDENTIAL Figure 6-32. Comparison of original and 2012 Adjusted off-peak MISO electricity price forecasts at MHEB.[148]

[148] SP-081 2012 Adjusted Electricity Price Forecast.

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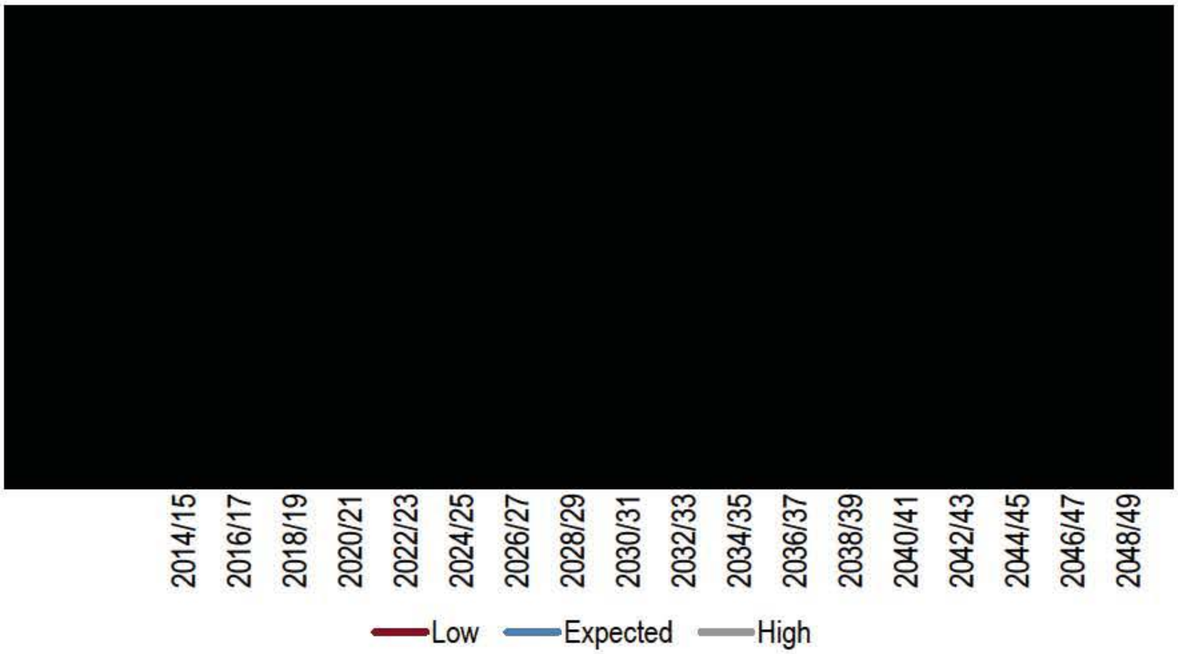
The final energy forecasts are shown below for the full 35-year period.

[redacted]

CONFIDENTIAL Figure 6-33. 2012 Adjusted forecast of peak energy prices at MHEB.[149]

[149] CONFIDENTIAL PUB/MH I-056b.



CONFIDENTIAL Figure 6-34. 2012 Adjusted forecast of off-peak energy prices at MHEB.[150]

<u>2013/2014 Price Forecast</u>

The 2013/2014 price forecast was based on an average of 20-year forecasts from six consultants:[151] [redacted].[152] MH moved from a 35-year consultant forecast to a 20-year forecast[153] because several natural gas price forecasts only went out twenty years, and it wanted full consistency between the electricity and natural gas price forecasts.[154]

The consultants make high, low, and reference cases, each of which are individually averaged to create high, low, and reference price forecasts.[155] However, MH did not do

[150] *Id.*

[151] NFAT Submission Appendix 9.3, p. 13.

[152] SPS-007 NFAT Confidential Sept 24 2013 Price Forecast Process.

[153] NFAT Submission Appendix 9.3, p. 9.

[154] SPS-007 NFAT Confidential Sept 24 2013 Price Forecast Process.

[155] NFAT Submission Appendix 9.3, p. 10.

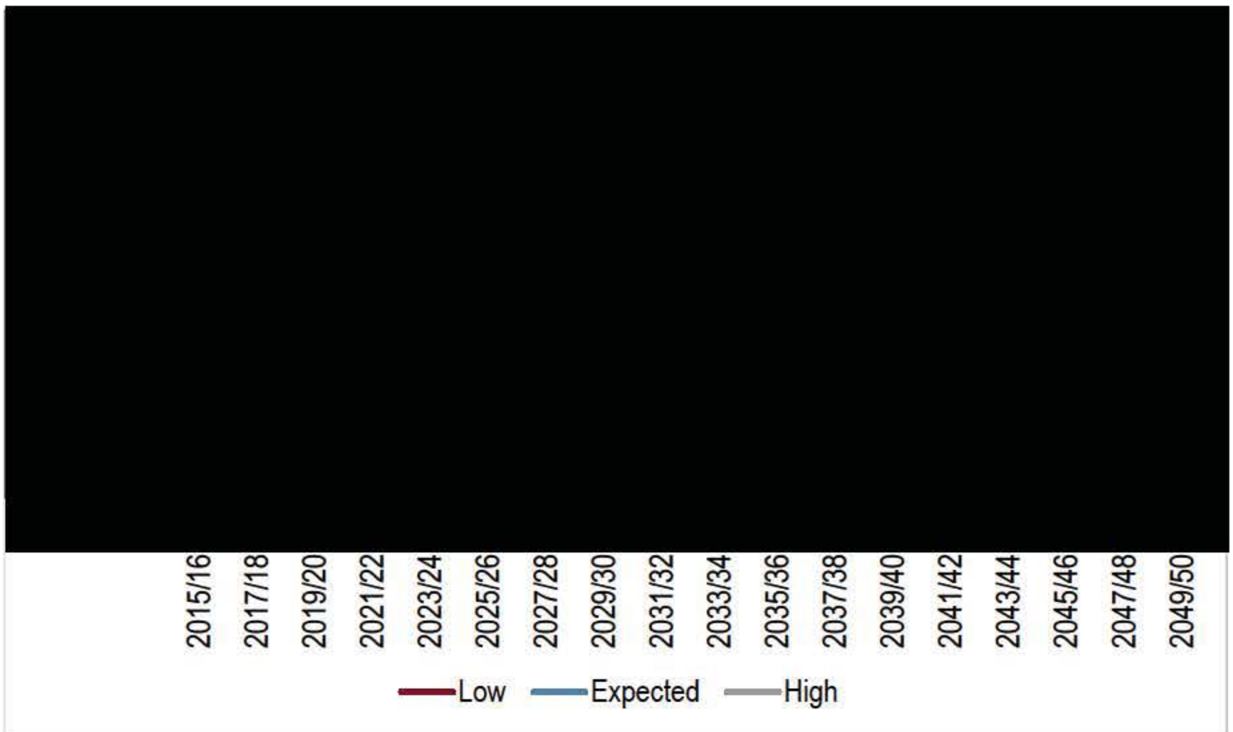
an uncertainty analysis for the 2013 update analysis, and, therefore, only used the reference price forecast.

Beyond twenty years, the electricity price forecasts had to be extrapolated. The extrapolation is based on the CAGR from the last five years of available forecast data (2030-2034). However, the same growth rate is not applied to each year of the extrapolation. Instead, the growth rates are linearly regressed to 0%/year by the final year of the forecast.[156]

The 2013/14 forecasts are also subject to the same adjustment for congestion and losses as the 2012 Adjusted Forecast.

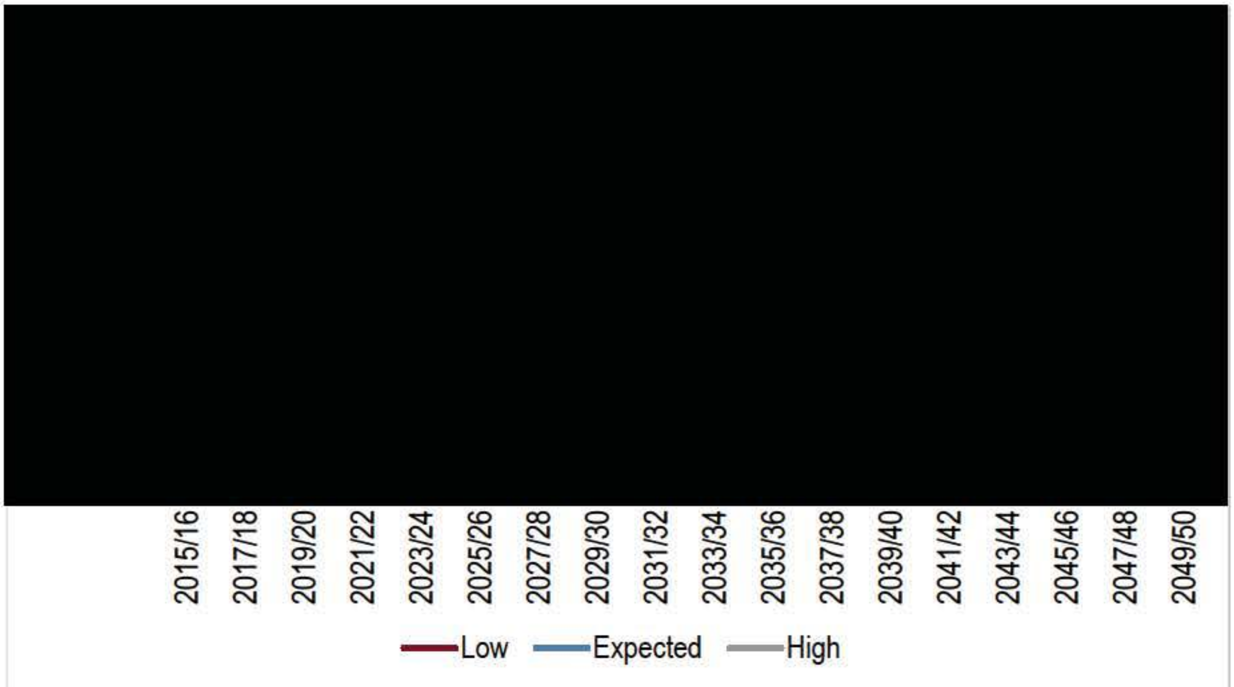
[156] *Id.*, p. 9.

The figures below show the updated forecast values for the full 35-year period modelled in SPLASH.



CONFIDENTIAL Figure 6-35. 2013/2014 consensus electricity peak energy price forecast at MHEB.[157]

[157] CONFIDENTIAL PUB/MH I-056b.



CONFIDENTIAL Figure 6-36. 2013/2014 consensus electricity off-peak energy price forecast at MHEB.[158]

Additional Adjustments

The energy and capacity forecasts are combined to create three market product forecasts:[159]

- Peak all-in (peak price + capacity price averaged over peak hours)
- Off-peak energy (straight off-peak price strip)
- Long-term dependable (all-in product + [redacted] premium[160])

The long-term dependable premium is described as follows:

"The price for the On-Peak Long-Term Dependable Product includes a premium over the shorter term On-Peak All-In Product. The exact amount

[158] *Id.*

[159] NFAT Submission Appendix 9.3, pp. 10-11.

[160] CONFIDENTIAL Manitoba Hydro, "2012 Electricity Price Forecast 2014-2028," pp. 11-12. Provided with the original Commercially Sensitive Information.

> of the premium is confidential as it is commercially sensitive. However, it represents the additional value a purchaser is willing to pay for the specific price and product attributes associated with power purchased from MH's dependable resources."[161]

However, for the low case, the long-term dependable 2012 Adjusted price forecast does not include a premium.[162]

Electricity Price Uncertainty

For the uncertainty analysis in Chapter 10 of the NFAT Submission, probabilities had to be assigned to the reference, high, and low 2012 Adjusted electricity price forecasts.[163] The probabilities are developed in a multi-step process, involving the prices of natural gas, carbon, and electricity.[164]

Natural Gas Uncertainty

The underlying probability distribution for the uncertainty in natural gas prices was developed by industry experts that assigned probabilities based on historical data, model runs, and expert judgment.[165] The industry experts developed low, reference, and high forecasts with associated probabilities of 25%, 50%, and 25% respectively.[166]

Of the low, reference, and high forecasts developed by the industry experts, only the reference forecast matched the EPO low, reference, and high natural gas price forecasts that MH used in its uncertainty analysis for the NFAT Submission.[167]

To apply the probability distribution developed by the independent experts to the EPO forecasts, MH determined a set of probabilities for the EPO low, reference, and high forecasts that had a mean and variance that would closely match the mean and variance

[161] NFAT Submission, Appendix 9.3, p. 11.

[162] CONFIDENTIAL PUB/MH I-056b.

[163] Chapter 12, which has the 2013 update analysis, is only at reference conditions.

[164] NFAT Submission, Appendix 9.3, pp. 41-43.

[165] SP-086 Moment Matching and Probability Distribution Explanation.

[166] *Id.*

[167] SP-081 NFAT Confidential – 2012 Adjusted Electricity Export Price Forecast.xlsx.

of the industry experts' low, reference, and high natural gas price forecasts. These probabilities were 35%, 45% and 20%.[168]

Carbon Uncertainty

MH relied upon a spread of carbon price forecasts from environmental market experts that assigned probabilities based on expert judgment.[169] The weightings were 35%, 40%, and 25% to its low, reference, and high forecasts respectively.[170] MH used these weightings for its own forecasts.

Electricity Price Uncertainty

MH estimated probabilities for each of the nine electric price forecasts that result from each of the different combinations of natural gas and carbon price forecasts using the combination of the natural gas and carbon price probabilities.[171] Using the regression equations provided above, the low-low, reference-reference, and high-high cases from the nine were used in the uncertainty analysis.[172] The probabilities for each of the three forecasts used in the uncertainty analysis were estimated using a mean and variance matching method to match the probabilities for the three forecasts with the probability distribution in the nine-branch distribution. The final probabilities for the electricity price forecasts were 30%, 55%, and 15% for the low, reference, and high cases respectively.[173]

C. **Capacity Exports**

MH has been making capacity sales for many years, and as indicated earlier, prior to June 2013 this was all through the bilateral market.[174] Historical annual revenues are shown in the table below.

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168 SP-086 Moment Matching and Probability Distribution Explanation.

169 *Id.*

170 NFAT Submission, Appendix 9.3, Figure 2.3, p. 42.

171 *Id.*

172 SP-081 NFAT Confidential – 2012 Adjusted Electricity Export Price Forecast.xlsx.

173 NFAT Submission, Appendix 9.3, Figure 2.3, p. 42.

174 LCA/MH I-381.

Fiscal Year	Bilateral Capacity Export Sales
2008/09	$ 58,381,083.14
2009/10	$ 53,371,558.44
2010/11	$ 47,752,094.30
2011/12	$ 46,587,812.79
2012/13	$ 46,416,499.22

Figure 6-37: Manitoba Hydro Historical Capacity Export Revenues.[175]

Capacity export revenues are included in the NFAT analysis through multiple means: a) long-term contracts include sales of capacity; and b) the long-term dependable price forecast includes a capacity component, and c) peak opportunity energy sales include [redacted]. Capacity prices are forecasted by the same consultants who forecast electric energy prices discussed in the previous section. Capacity sales must include firm transmission service.[176] MH anticipates that with a new 250 MW or 750 MW interconnection with MISO, there will be adequate firm transmission capacity to sell all available surplus capacity.[177]

D. Ancillary Services Exports

MH does not assume the ability to produce ancillary services revenue will increase substantially if the Preferred Development Plan is implemented. First, the size of the interconnection with MISO does not significantly affect the amount of ancillary services MH may offer into MISO as an EAR since MISO rules limit the amount of ancillary services that can be carried by any single resource to 20% of the system-wide requirement and an EAR is considered a single resource.[178] No ancillary services revenues were included in the economic NPV analysis as they were assumed to be independent of the specific development plan.[179]

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[175] *Id.*

[176] LCA/MH I-380.

[177] *Id.*

[178] LCA/MH I-374.

[179] LCA/MH I-379.

E. Issues with Export Market Modeling

Pricing Premiums

MH has made the assumption that it will be able to export surplus hydropower not yet under contract—so-called "non-committed" firm sales—at premium prices. However, there is no guarantee that MH will be able to sell this power on a long-term basis. MH provided data on actual sales of surplus dependable energy compared to assumptions of surplus dependable energy in its Power Resource Plans, and found that the actual volume sold is typically less than the assumed amount.[180] Using this data, Potomac Economics recommends assuming only 91% of forecast surplus dependable energy can be sold on a long-term basis.[181]

In addition, MH provides little justification for the amount of the premium other than to say it is representative of:

- The additional amount a purchaser is willing to pay for the specific price and product attributes associated with power purchased from MH's dependable resources[182] as well as price and volume certainty.[183]
- MH's experience and ability to attain a higher value for a long-term product sourced from dependable resources.[184]

"Non-committed" firm sales are an important part of the economic analysis of the Preferred Development Plan. For Plan 14, which models the Preferred Development Plan, "non-committed" firm sales revenues occur through fiscal year beginning 2038, whereas in in Plan 1, which models the All Gas Plan, these revenues occur only through fiscal year beginning 2020.[185] This is because "non-committed" firm sales cease after natural gas generation is added to the development plans because only surplus hydro-

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[180] SP-055 NFAT Confidential Potomac Dependable Sales October 24 presentation.

[181] Potomac Economics, "Report on Export Prices and Revenues relating to the Need for Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," p. 44.

[182] NFAT Submission, Appendix 9.3, p. 11.

[183] CONFIDENTIAL Manitoba Hydro, "2012 Electricity Price Forecast 2014-2028," p. 12. Provided with the original Commercially Sensitive Information.

[184] *Id.*

[185] SP-011 NFAT Confidential – Economic Cash Flows.xls.

electric energy is considered for "non-committed" firm sales in MH's analysis.[186] For the All Gas Plan, "non-committed" firm sales are about [redacted] through fiscal year beginning 2020 or about [redacted] of total export volume during the same period, whereas for the Preferred Development Plan, "non-committed" firm sales are about [redacted] through fiscal year beginning 2038 or about [redacted] of total export volume during the same period.[187]

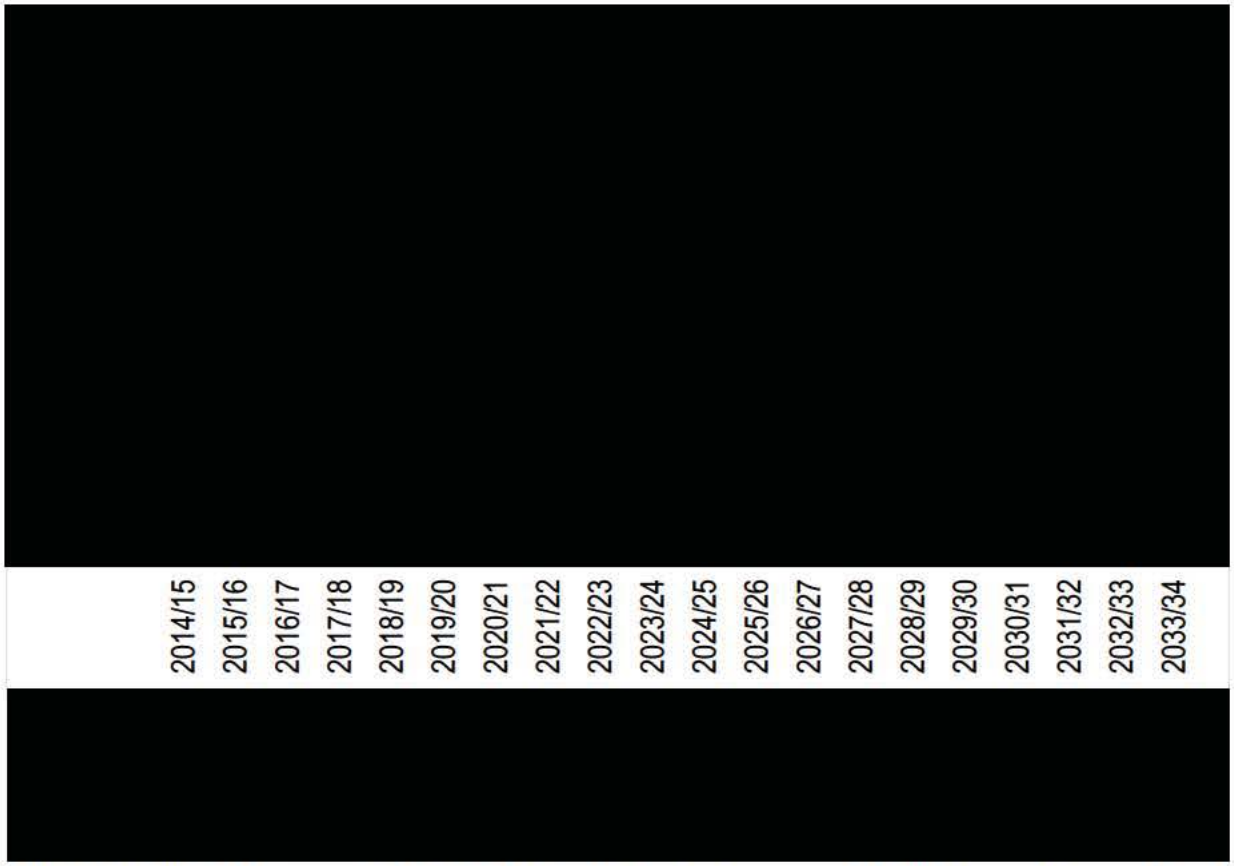
The value of the premium pricing is displayed graphically in the figure below, which shows the long-term dependable price forecast used for "non-committed" firm sales and the price forecast for regular peak opportunity energy sales. Energy, capacity, and the additional premium are each shown separately. The chart shows opportunity sales are priced about [redacted] lower than firm sales before 2020/21 and about [redacted] lower thereafter.

As a first order approximation, if the percentages above are applied to the difference in annual "non-committed" firm revenues for the All Gas and Preferred Development Plan cases, the total reduction in revenue is about [redacted] in 2014$ or [redacted] on an NPV basis at the reference discount rate.[188] This is about [redacted] of the total difference in the NPV of total export revenues between these two cases. Using Potomac Economics' recommendation that only 91% of surplus dependable energy could be sold long-term, the total reduction in revenue would be only about [redacted] in total or [redacted] on an NPV basis, which is only about [redacted] of the total difference in the NPV of total export revenues between these two cases.

186 SP-011 NFAT Confidential – Economic Cash Flows.xls.

187 SP-131 NFAT Confidential - REVISED Economic Cash Flows Energy Exports V4 energy and revenue only.xls.

188 SP-011 NFAT Confidential – Economic Cash Flows.xls. This would be the same for a 78-year and 35-year NPV as "non-committed" firm sales for the Preferred Development Plan drop to zero after fiscal year beginning 2038.



CONFIDENTIAL Figure 6-38: Manitoba Hydro "non-committed" firm sales and peak opportunity sales pricing comparison for the 2012 Adjusted forecast.[189]

[redacted].[190] The figure below shows the low case long-term dependable electricity price forecast compared to the reference case on-peak electricity price forecast used for opportunity sales. [redacted]

[189] CONFIDENTIAL PUB/MH I-056b and SP-010 2012 Adjusted Electricity Price Forecast.xls.

[190] CONFIDENTIAL PUB/MH I-056b.

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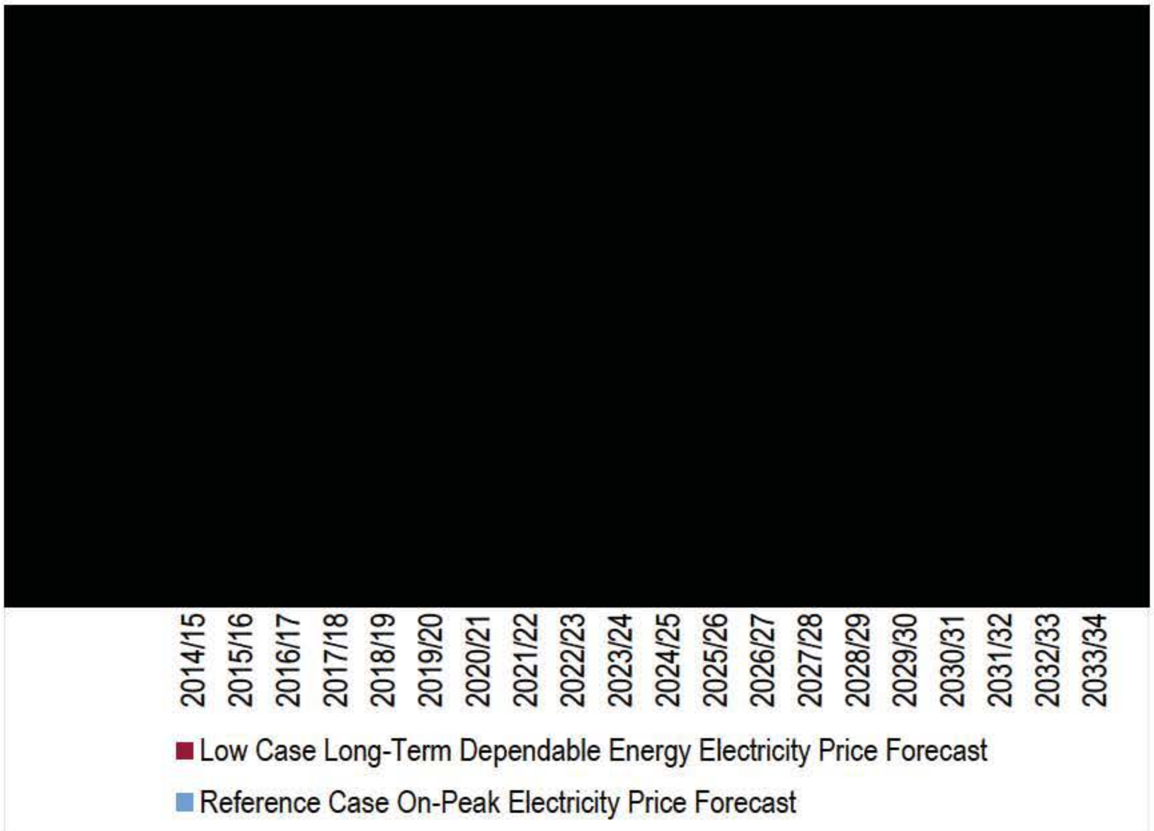

CONFIDENTIAL Figure 6-39: Manitoba Hydro's low case long-term dependable electricity price forecast compared to its reference case on-peak electricity price forecast used for opportunity sales. All numbers are for the 2012 Adjusted forecast.[191]

Potomac Economics also expressed concern regarding MH's assumption that it can receive revenue for peak opportunity sales at prices in excess of MISO energy prices.[192] As shown in Figure 6-38, about [redacted] of the peak sales price is attributable to capacity sales through 2019/20 and about [redacted] of the peak sales price is attributable to capacity sales from 2020/21 through the first twenty years of the study period. As a first order approximation of the impact of this premium on peak opportunity sales revenue, the difference in peak export opportunity sales revenues between the All Gas and Preferred Development Plan has been reduced by these percentages. For years past 2033/34, the

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[191] CONFIDENTIAL PUB/MH I-056b and SP-010 2012 Adjusted Electricity Price Forecast.xls.

[192] Potomac Economics, "Report on Export Prices and Revenues relating to the Need for Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," pp. 44-45.

percentages were extrapolated assuming constant real capacity price.[193] The reduction in NPV out to 2090 at the MH reference discount rate is approximately [redacted] or about [redacted] of the total difference in the NPV of total export revenues between these two cases.[194] Similarly, if [redacted] of the difference in "non-committed" firm sales revenues between the two plans were reduced by an amount equal to the fraction of the long-term dependable electricity price forecast attributable to [redacted] of the capacity price, the reduction in NPV out to 2090 at the MH reference discount rate is approximately [redacted] or about [redacted] of the total difference in the NPV of total export revenues between these two cases.[195]

Exports of Natural Gas Generation

MH specifically excludes consideration of the potential to export natural gas-fired generation as firm sales. SPLASH does allow natural gas to generate to and make opportunity sales when economic.

There are many important factors to consider when evaluating the potential to export natural gas generation to MISO from Manitoba, including:

1) **Resource Diversity:** Given the heavy coal reliance in the MISO region, natural gas generation additions would add some resource diversity, but not to the same extent as large hydro if MISO utilities begin building natural gas plants en masse to replace retiring coal units.
2) **Environmental Issues:** Hydro is seen as more environmentally friendly compared to natural gas, as it does not involve burning fossil fuels to generate power. However, natural gas generation still has a lower environmental impact than coal generation, which is especially important if future polices restrict carbon emissions in the US.[196]

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193 This is consistent with Potomac Economics' finding that there is "no basis for assuming the real [capacity] price will increase after 2034." See Potomac Economics, "Report on Export Prices and Revenues relating to the Need for Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," p. 45.

194 CONFIDENTIAL PUB/MH I-056b; SP-011 NFAT Confidential – Economic Cash Flows.xls.

195 *Id.*

196 For more on environmental issues, see Technical Appendix 4: Environmental Issues and Policy.

3) **Wind Synergy:** Hydro provides energy storage, which can help smooth fluctuations in power production from wind energy. The western MISO region has seen significant growth in wind capacity in recent years.[197] Although the planned Keeyask and Conawapa hydro projects do not add more water storage through significant new reservoirs, they would increase the generation potential of water stored in Lake Winnipeg and other existing reservoirs in MH's system.[198]
4) **Transmission Losses:** MH natural gas generation would have to compete with locally-sited plants to serve MISO load. MH directly cites this as the reason it faces a competitive disadvantage in attempting to export natural gas-fired generation.[199]
5) **Competition with other Generation Types:** Coal generation dominates the MISO region, and wind power has been rapidly expanding. Although coal retirements are expected along with new transmission to better integrate wind power, the role of gas-fired generation in the western MISO region is not entirely certain at this time.

The chart below shows monthly fuel mix for the MISO market from January 2011 through September 2013. The chart shows that in the first part of 2012, gas generation caused significant displacement of coal generation due to record low gas prices that year.

[197] NFAT Submission, Appendix 5.3, p. 57.

[198] For more on how the planned hydro developments will impact the Manitoba Hydro water regime, see Technical Appendix 4: Environmental Issues and Policy.

[199] PUB/MH I-103c.

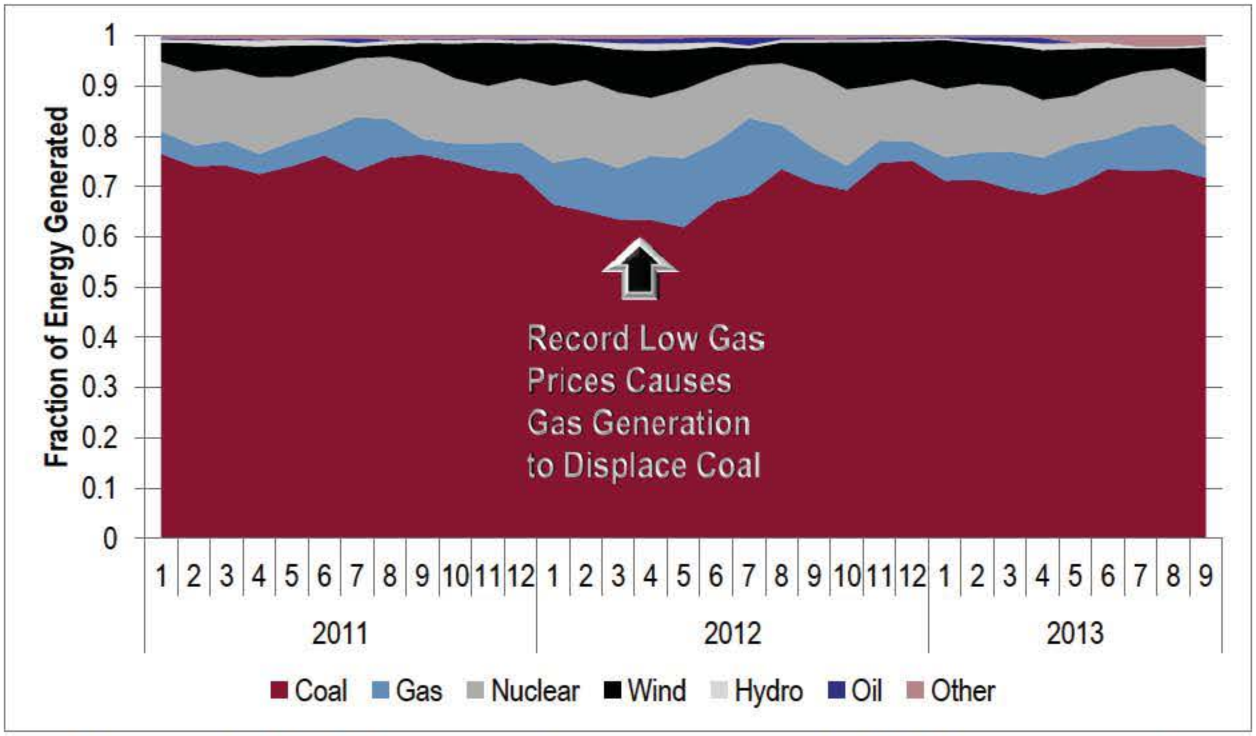

Figure 6-40: Monthly fraction of energy generated in MISO by fuel type.[200]

This MISO data indicates the potential for natural gas generation exports to MISO would be much greater in a future with sustained low natural gas prices and/or high carbon prices. Potomac Economics has investigated the potential for expanded shale gas production to create a low gas price future, and views this potential future as having a high enough probability to be seriously considered.[201] However, even if low natural gas prices were to be sustained going forward, a lower delivered natural gas price in Manitoba compared to the western MISO region would likely be needed to overcome disadvantages of Canadian natural gas generation compared to US natural gas generation due to transmission losses. MH currently argues that Manitoba and MISO natural gas-fired generators would use natural gas supplies of "similar cost" and that

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[200] From MISO Monthly Market Assessment Reports, https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/MonthlyMarketAnalysisReports.aspx.

[201] Potomac Economics, "Report on Export Prices and Revenues relating to the Need for Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," p. 27.

transmission losses are a significant barrier to exporting natural gas-fired generation to MISO.[202] More on this issue will be discussed in the supplemental filing of Technical Appendix 9B: Economic Analysis.

Reliance on Historical Data

MH's monthly subperiod pricing relies on historical data to define the range of market prices within each year of the SPLASH analysis. This assumes that changes in the MISO market fundamentals do not alter the temporal price relationships within a year. MISO market prices have historically been set by coal units for most hours in the year and by gas prices for a more limited number of hours in the year.[203]

MH relies on historical market data for several steps in its modeling, including:

- Adjusting for congestion and losses between MINN Hub in MISO and the MHEB node at the Manitoba border with the US;
- Estimating monthly patterns in peak and off-peak market prices; and
- Estimating variability in peak and off-peak prices within each month.

The annual consensus price forecast using data from modeling performed by independent consultants does model the anticipated effects of changes in the MISO marketplace.

With retirements of units, load growth, potential carbon emissions pricing, and potential low gas prices, the historical relationships may not provide reasonable representation of future market conditions. Some of the anticipated changes in the MISO market may impact these patterns as well as the annual prices. For instance, if natural gas becomes a bigger part of the supply mix in MISO, there is the potential for natural gas supply constraints during cold winters where natural gas is also needed for heating. This could cause winter electricity prices to rise relative to average prices. On the other hand, increased wind generation could cause conditions with surplus wind, especially in non-summer months during nighttime hours. This could lead to lower

[202] PUB/MH I-103c.

[203] NFAT Submission, Chapter 3, pp. 33:25-34:1.

prices in non-summer seasons or lower numbers of hours in non-summer months with high prices.

Potomac Economics has performed an analysis of future MISO congestion and losses. Losses were estimated using historical data from 2011-2012 and held constant through the study period.[204] It also performed an analysis of MISO congestion patterns, which relied on a regression based on historical data, also from 2011-2012.[205] To account for changes to transmission topology on congestion, Potomac Economics concluded that it is reasonable to assume transmission congestion from wind generation will likely remain the same going forward, as wind generation additions will be accompanied by significant new transmission investment, and so Potomac Economics capped the impact of the share of wind generation in MISO's fuel mix on congestion in 2015.[206] Potomac Economics' forecast of MISO prices is also done on an annual basis, and so does not provide a lot of insight into seasonal pattern changes, but its assumptions and methods do not seem inconsistent with MH's.

Given the multitude of potential changes, it is not possible to say what the impacts of assumptions based on historical data would be to the economics of the Preferred Development Plan without more detailed analysis including dispatch modeling.

Process for Estimating Price Coefficients in SPLASH

Section IV-A of this Technical Appendix discusses how MH models opportunity sales in SPLASH using price coefficients that shape the annual price forecasts into a "step-function." LCA has some concerns regarding this process.

MH relies on historical MISO prices to estimate the price coefficients. MISO historical prices can be sampled in different ways, for instance it can be hourly, daily, weekly, etc. The choice of sampling frequency will impact the resulting price coefficients. In general,

[204] Potomac Economics, "Report on Export Prices and Revenues relating to the Need for Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," p. 28.

[205] *Id.* p. 29.

[206] *Id.*, pp. 32-33.

a higher sampling frequency, such as hourly as opposed to daily, will tend to result in a steeper "step function" that is one with higher highs and lower lows.[207] According to data presented in a document MH provided to LCA on SharePoint,[208] it appears that MH used [redacted] price sampling for the NFAT Analysis. This means [redacted] MISO prices form the pricing probability curve the block prices are based upon.

The figure below illustrates how using daily and hourly price sampling would change the resulting block prices for April 2011 peak prices—the same historical prices used for many of MH's figures presented in Section IV-A. The solid blue line represents the probability distribution based on daily average prices, and the corresponding dashed blue line represents the average block prices if said curve is divided into [redacted] blocks. The solid red line represents the probability distribution based directly on hourly prices, and the corresponding dashed red line represents the average block prices if said curve is divided into [redacted] blocks. Overall, using hourly data creates a pricing step function with [redacted]

[207] LCA/MH I-105, Attachment, pp. 47-49.

[208] SP-025 NFAT Confidential Market Coefficients in SPLASH.

[redacted]

CONFIDENTIAL Figure 6-41: Comparison of potential block prices for April 2011 peak hours using different MISO data sampling frequency. Based on data from GlobalView.

[redacted]

[redacted]

Ultimately, it is not known how much of an impact this issue would have on the SPLASH modeling used for the NFAT analysis. However, it is still an important assumption to consider when reviewing the results.

F. Conclusions Regarding Export Market Modeling

LCA has found several issues of concern with MH's modeling of export (and import) markets. However, for several of them, it is not clear whether they would impact the comparison of development plans for the NFAT analysis in any significant way. The biggest concern is that pricing premiums used to model some transactions, especially the sale of surplus dependable hydro energy, are not well documented. Nor has it been proven that MH will be able to sell all of its surplus dependable hydro energy on a long-term basis. More on the potential economic impact of these issues will be explored in Technical Appendix 9B: Economic Analysis. But even these issues are generally much smaller than the biggest uncertainty in modeling export markets, which is the level of forecasted export market prices. It is not known with any certainty whether MISO prices will increase back to levels experienced prior to 2009 or not. Potomac Economics has performed an analysis of the MISO market and of MH's export market price forecast, which should be taken under careful consideration, and will also be analyzed in more detail in Technical Appendix 9B: Economic Analysis.