REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1; Page No.: 2-39; Chapter 11: Financial Evaluation of Development Plans, Section 11.0-11.5, p. 1-23

PREAMBLE: Probabilistic Analysis based upon Plans in Question LCA-003

QUESTION:

Please run the analysis for The Adjusted Plans 1, 1A, 2, 3, 4, 12 and 14 that was provided in Chapter 10 and Chapter 11 providing all similar tables and figures. Note this request assumes the need to run the SPLASH Model, the Economic Model and the Financial Model for all the 26 scenarios that were modeled in addition to the reference scenario in Question LCA-003. Please include the results of Question LCA-003 in your tables and figures. For the purposes of the S-curves and tables provided please do not subtract the values the All Gas Case at the Reference Scenario from the outcome of each plan for each scenario.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Volume: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1; Page No.: 2-39; Chapter 11: Financial Evaluation of Development Plans, Section 11.0-11.5, p. 1-23

PREAMBLE: Probabilistic Analysis based upon the Plans in Question LCA-003 using adjustments in Question LCA-005

QUESTION:

Please run the analysis that was provided in Chapter 10 and Chapter 11 for The Adjusted Plan 14 in Question LCA-005, The Preferred Development Plan, further deferring the timing of the 750MW Interconnection line with the US to be in service the year prior to the adjusted in-service date for the Conawapa G.S., providing all similar tables and figures. Note this request assumes the need to run the SPLASH Model, the Economic Model and the Financial Model for all the 26 scenarios that were modeled in addition to the reference scenario in Question LCA-005. Please include the results of Question LCA-005 in your tables and figures. For the purposes of the S-curves and tables provided please do not subtract the values from the All Gas Case at the Reference Scenario from the outcome of each plan for each scenario.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1; Page No.: 2-39; Chapter 11: Financial Evaluation of Development Plans, Section 11.0-11.5, p. 1-23

PREAMBLE: Probabilistic Analyses with Reduced Thermal Capital Cost Uncertainty

QUESTION:

Please re-run the probabilistic analysis in Questions LCA-004 and LCA-006 assuming that the uncertainty in the capital cost for thermal generation is +/- 20% rather than the ranges used in Chapter 10.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 6.1 Summary of Terms and Conditions of Export Contracts; Section: WPS (System Participation and Surplus Energy Sales); Page No.: 4

QUESTION:

Please provide the most recent draft copy or term sheet of the WPS contracts that are still under discussion.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

Regarding the contracts listed in Table 6.4: Please provide a table with a list of all export contracts Manitoba Hydro has ever signed with the customers/counterparties listed in the table. Use the same column headings as the table.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

Please provide a table with a list of all export customers or contracts contingent on new hydro generation development in Manitoba that Manitoba Hydro considered, but did not sign. Use the same column headings as Table 6.4 where possible.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

For each contract contingent on new hydro generation development in Manitoba that Manitoba Hydro considered but did not sign, please list the reasons Manitoba Hydro did not end up signing each potential agreement.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 6.1 Summary of Terms and Conditions of Export Contracts; Section: NSP 125; Page No.: 3

QUESTION:

How does Manitoba Hydro intend to meet the condition precedent that Manitoba Hydro awards on or before May 1, 2018 the major general civil contract for the construction of a new hydraulic generating facility that has an installed capacity of at least 1,000 MW and will have a targeted in-service date of on or before May, 2021 found in the Northern States Power 125 MW System sale agreement?

RESPONSE:

"The condition precedent set out in Section 14.1(9) of the Northern States Power 125 System Power Sale Agreement (the "Agreement") which requires the awarding by Manitoba Hydro, on or before May 1, 2018, of the major general civil contract for the construction of a new hydraulic electrical generation facility with an installed capacity of at least 1000 MW with a targeted in-service date of May 1, 2021 is within the sole and absolute discretion of Manitoba Hydro. Based upon Manitoba Hydro's current development plan, this condition cannot be met. On or before May 1, 2018, Manitoba Hydro will examine the circumstances and determine at that time whether it will waive the condition and proceed with the Agreement or rely on the condition in order not proceed with the Agreement."

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 16

QUESTION:

Please provide a copy of each contract listed in Table 1.4.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 16

QUESTION:

Please provide an estimate of the likelihood Manitoba Hydro would renew each contract listed in Table 1.4 at the end of the specified term, or enter into a similar contract with the same counterparty in the future.

RESPONSE:

The following contracts listed in Table 1.4 have been renewed:

GRE 200 MW Diversity Exchange PPA term is Nov 2014 to April 2030;

MMPA 30 MW Energy Sale PPA term is May 1, 2012 to April 30, 2017;

MP 50 MW System Power Sale Term Sheet term is May 2015 to May 2020;

SMMPA 50 MW ZRC Sale term is June 2013 to May 2014;

WPS 108 MW Energy Sale PPA term is June 2012 to May 2023.

The Lake St. Joseph Agreement with Ontario has an indefinite term.

Manitoba Hydro expects Northern States Power will go to market to replace the 375/325 MW and 125 MW Power Sales Agreements within the next several years.

Should Manitoba Hydro have sufficient capacity and energy resources available at that time Manitoba Hydro will compete to meet NSP's requirements. Manitoba Hydro cannot estimate the likelihood of being the successful supplier however it would note that an ongoing arrangement with NSP for this need has been in place since 1980.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 16

QUESTION:

Regarding each of the contracts listed in Table 1.4, please identify any customers that have indicated a firm desire not to renew any of these contracts or enter into contracts with Manitoba Hydro in the future along with all reasons the customer has stated they do not wish to pursue a new contract.

RESPONSE:

Please see the response to LCA/MH I-0015 for a list of contracts which have been renewed. No customers have indicated a firm intention not to renew or enter into contracts with Manitoba Hydro in the future.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

Regarding the WPS contract still under negotiation, when does Manitoba Hydro anticipate negotiations will be completed?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

Regarding the WPS contract still under negotiation, in the event no agreement is reached, would Manitoba Hydro pursue alternative arrangements only with other customers in Wisconsin, or would it consider other potential export markets and what other markets would it pursue?

RESPONSE:

Manitoba Hydro is actively pursuing arrangements within all its markets. In the hypothetical if this arrangement with WPS were not to proceed, MH would consider alternative arrangements in all markets including Minnesota, Wisconsin, North Dakota, Saskatchewan and Ontario.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

For each of the mitigation provisions listed in section 15.2.2.1, please describe whether Manitoba Hydro has commonly used the provision for past export contracts or whether this is a new provision specifically for the new contracts.

RESPONSE:

The mitigation provisions of Curtailments and Curtailment Priority Criteria, Creditworthiness and Conditions Precedent have been utilized by Manitoba Hydro in past and new export contracts. The mitigation provisions of Market Access, Alternative Supply, Adverse Water and Conditions and Options have primarily been utilized by Manitoba Hydro in the new export contracts.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

For each of the mitigation provisions listed in section 15.2.2.1, please list all the Manitoba Hydro contracts in Tables 1.4 and 1.8 in Appendix 9.3 which include each mitigation provision.

RESPONSE:

The following table identifies the mitigation provisions from section 15.2.2.1 that are included in the contracts listed in Table 1.4, 1.8 and Appendix 9.3.

Contract	Curtailments & Priority Criteria	Alternative Supply	Adverse H2O Conditions	Creditworthiness	Conditions & Options	Conditions Precedent
Table 1.4						
GRE 150 SD	No	No	No	No	No	Yes
GRE 200 SD	Yes	Yes	No	Yes	No	Yes
MMPA 30	Yes	No	No	Yes	No	Yes
MP 50	Yes	Yes	No	Yes	No	Yes
MP 50 Term Sheet	Yes	Yes	Yes	No	No	Yes
NSP 150 SD	No	Yes	No	No	No	Yes

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

For each of the mitigation provisions listed in section 15.2.2.1, please list all the Manitoba Hydro contracts contingent on new hydro development in Table 6.4, which include each mitigation provision.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

If any of the mitigation provisions listed in section 15.2.2.1 have been commonly implemented in past Manitoba Hydro export contracts, please identify past instances where the provision successfully mitigated any negative outcomes for Manitoba Hydro and its ratepayers.

RESPONSE:

The mitigation provisions listed in Section 15.2.2.1 have mitigated negative outcomes for Manitoba Hydro and ratepayers. A description of some instances in which Manitoba Hydro has utilized these provisions is provided below:

Market Access

Manitoba Hydro has utilized the firm transmission service associated with the current GRE 150 SD contract to sell surplus energy at times when non-firm transmission service had a significant likelihood of curtailment and the energy had a very high probability of spill.

Curtailments and Curtailment Priority

Manitoba Hydro has utilized the curtailment and curtailment priority provisions in the export contracts to curtail the delivery of energy to these customers in order to continue to provide for the needs of domestic customers. Examples of periods in which exports were curtailed in order to protect domestic load include the temporary loss of generation at the Long-Spruce Generating Station due to icing conditions in November 2012 and the loss of Manitoba Hydro's HVDC transmission facilities due to a wind storm event in September 1996.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

If any of the mitigation provisions listed in section 15.2.2.1 have been commonly implemented in past Manitoba Hydro export contracts, please list any improvements to risk mitigation Manitoba Hydro has introduced from its past experience with the provision.

RESPONSE:

The risk mitigation provisions listed in Section 15.2.2.1 are utilized in Manitoba Hydro's export contracts as a result of (i) the evolution of market products offered through the MISO market (ii) inclusion of surplus energy sales in long-term contracts that require an ability to curtail in adverse water conditions and (iii) sales that require conditions and options and conditions precedent as the sale requires new generation and/or transmission facilities to be added to Manitoba Hydro's system in order to be able to supply the sale.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 17; 19

QUESTION:

For each of the contracts listed in Tables 1.5 and 1.7, please list which ones were modeled in each of the 15 development plans listed in Chapter 9, Table 9.3.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 21; 22

QUESTION:

For each of the contracts listed in Tables 1.9 and 1.11, please list which ones were modeled in each of the development plans listed in Chapter 12, Tables 12.3 and 12.8.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.3.2; Page No.: 30

QUESTION:

What is the cost of the 200 MW of new transmission service required by the 300 MW sale to WPS assumed in the evaluation of the preferred development plan?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.3.2; Page No.: 30

QUESTION:

Please identify any transmission upgrades necessary to facilitate the 200 MW of new transmission service required by the 300 MW sale to WPS and their cost.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.3.2; Page No.: 30

QUESTION:

Please provide copies of any MISO or Manitoba Hydro study to determine availability of 200 MW of transmission capacity to facilitate the 300 MW sale of power to WPS.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58-59

QUESTION:

Regarding the 250 MW of new transmission service required by the 250 MW sale to MP, please provide copies of any MISO or Manitoba Hydro study to determine availability of 250 MW of transmission capacity to facilitate the sale.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.3.2; Page No.: 52

QUESTION:

Please provide a copy of the MOU with SaskPower.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.3.2; Page No.: 52

QUESTION:

Please provide an update on the likelihood that Manitoba Hydro will enter into a new power import or export agreement with SaskPower.

RESPONSE:

As Manitoba Hydro and SaskPower have signed a 25MW Term Sheet from 2015-2022, the likelihood that a final agreement will be reached is very high. A signed agreement is expected by mid-2014.

REFERENCE: Executive Summary; Section: Preferred Development Plan Facilities; Page No.: 7

QUESTION:

Please provide copies of written correspondence between Manitoba Hydro and WPS discussing WPS's decision not to pursue investment in the proposed 750 MW transmission interconnection.

RESPONSE:

There is no written correspondence documenting the WPS decision.

REFERENCE: Chapter 14: Conclusions; Section: 14.7; Page No.: 52

QUESTION:

Please describe in detail the "greater enhancements to other benefits" Pathway 4 plans have compared to Pathway 3.

RESPONSE:

The following restates the summary comparison of Pathway 4 compared to Pathway 3 and provides the "greater enhancements to other benefits" Pathway 4 plans have compared to Pathway 3.

<u>Summary Comparison of Pathway 4 with Pathway 3</u>

- Pathway 4 (750 MW Interconnection, No WPS 300 MW sale or investment in transmission).
- Pathway 3 (250 MW Interconnection).
- Both involve Keeyask 2019, MP 250 MW Sale, 100 MW WPS Sale, 125 MW NSP Extension.

The Pathway 3 and 4 plans are competitive with each other depending on the situation. The economic evaluations considering the 27 scenarios indicate no clear overall preference between Pathways 3 and 4 and suggest that:

- If there is an expectation Conawapa will be built in the next two decades, the 750 MW interconnection (Pathway 4) is more economic.
- If there is an expectation Conawapa will not be built for several decades, the 250 MW interconnection (Pathway 3) is more economic.
- The most economic plan with the 250 MW interconnection (Pathway 3) is more economic than the most economic plan with the 750 MW interconnection (Pathway 4).

Similarly, the financial evaluations indicate no clear overall preference between Pathways 3 and 4. K19/Gas/250MW (Pathway 3) and K19/Imp/Gas/750MW (Pathway 4) show the same long-term cumulative rates increases under the reference scenario. K19/C25/250MW (Pathway 3) and K19/Imp/C31/750MW (Pathway 4) also show the same long-term cumulative rates increases. Development plans with either a new 250 MW or 750 MW interconnection and Conawapa (K19/C25/250 or K19/Imp/C31/750) are 32% lower compared to development plans with either a new 250 MW or 750 MW interconnection and Keeyask only (K19/Gas/250MW and K19/Imp/Gas/750MW).

While net costs of the 250 MW and 750 MW interconnection plans are competitive with each other depending on the situation, Pathway 4 plans with the 750 MW interconnection have more flexibility to respond to changing circumstances and to take advantage of new sales or other opportunities and provide greater cost savings, compared to Pathway 3, as well as providing greater enhancements to other benefits.

With the 750 MW interconnection, Pathway 4 provides the benefits of the large interconnection but without the WPS sale driving a requirement to undertake significant generation investment overlapping with Keeyask—this spacing of investment intervals is representative of plans which have the next generation for 2033 being either Conawapa or gas, depending on the conditions at that time. Should factors such as energy price trajectories, new export contract opportunities, and capital costs be favourable, Conawapa could be advanced from 2033 to as early as 2026. Compared to the 250 MW interconnection, the larger interconnection would provide much greater export and import capacity to take advantage of such opportunities.

Thus, Pathway 4 allows the opportunity to negotiate long-term firm contracts with US entities other than MO. Pathway 4 also would be beneficial if long term contracts were negotiated with SaskPower because it would provide an additional outlet for the surplus power from Conawapa which likely would be needed for such a sale. This allows variations of Pathway 5 to be pursued if opportunities present themselves. A 250 MW interconnection does not support additional sales opportunities.

250MW Interconnection in Pathway 3 At Risk Of Not Obtaining Approval

An advantage of Pathway 4 is that Minnesota Power (the US entity planning, obtaining regulatory approval, procuring the property and building the line) is fully committed to the 750 MW interconnection and has confidence as to obtaining the necessary approvals. The 250 MW interconnection is significantly more expensive for MP, is not as advanced and does not provide significant economic or reliability benefits to Minnesota or the MISO region. MP has taken the position in its Certificate of Need filing on October 21, 2013 (Section 7.4.2.1 page 77) that "such a project would not meet the long-term needs of the region and would not prove to be cost-effective for customers or environmentally preferable over the long-term." As such, the 250MW interconnection has greater risk of not being approved and proceeding.

Minnesota Power has also stated in its Certificate of Need filing (Section 2.1 pages 11-13) that the new 500 kV tie line project facilitates an innovative wind storage provision that leverages the flexible and responsive nature of hydropower to optimize the value of Minnesota Power's wind energy investments. The project at minimum is required to facilitate the delivery of 383 MW of hydropower and wind storage products to serve Minnesota Power customers. The large capacity line also has the potential to improve regional reliability by lowering the size of the largest single contingency in the region.

MP has made application to build one line of the right size for the region. In its Certificate of Need filing (Section 7.4.2.1 page 78) MP states that "building the new tie line large enough the first time should limit proliferation of new transmission line corridors in the future."

The Manitoba Hydro Wind Synergy Study report has demonstrated the challenges of integrating large amounts of variable generation in the MISO footprint and the benefits to Minnesota of having access to a large amount of energy storage. The new 500 kV line along with increased storage capacity was shown to improve savings in production cost, load cost, reserve cost as well as reduce wind curtailment. A lower capacity line greatly reduces these regional benefits for the state of Minnesota. Legislation was passed in 2013 in Minnesota for a renewable energy integration and transmission study to be completed to examine the requirements for the state to achieve 40% by 2030. Having a high capacity line in place in this timeframe is strategic for Manitoba Hydro to help the state of Minnesota achieve their potential renewable energy goals. For more information on this initiative see:

http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/minnesota-renewable-energy-integration-transmission-study.jsp

Final discussions are underway with WPS regarding a sale of up to 500 MW on top of the 383 MW to MP. Once the final agreements are complete the interconnection size will need to be optimized. Studies are planned to begin shortly to optimize the 750 MW plan to potentially facilitate up to 900 MW of transfer capability.

If the interconnection is developed as a 500 kV line capable of 750 MW transfer, there also is the potential for Manitoba Hydro to take advantage of a potential upgrade to 1100 MW if MISO undertakes improvements to and out of the Blackberry substation in Minnesota. This would further increase system reliability and economic opportunities for Manitoba Hydro.

Pathway 4 would also enhance other benefits such as:

Protects Customer Service

By having increased access to imports and by having increased domestic generation, Pathway 4 compared to Pathway 3 provides a higher level of system reliability to address generation or major transmission outages or unexpectedly high load peaks, and the higher level of energy security to mitigate unexpectedly severe droughts or unexpectedly high energy consumption. Please refer to the attachment.

Supports Risk Management and Flexibility

Pathways 4 provide the overall best means to respond to changing conditions such as higher or lower load growth, uncertainty in level of future DSM, increases and decreases in river flows due to climate change and additional export market opportunities. The large new interconnection to the Wisconsin region reduces export revenue risk by providing enhanced market and customer diversification. The 750 MW interconnection has also been designed to increase firm import capability. During times of lower than average water flows the additional import capability will provide Manitoba Hydro with access to an additional 2,000 GWh of lower cost off-peak energy which will significantly reduce Manitoba Hydro's financial exposure to drought. The same import capacity also provides protection against a delayed Keeyask ISD caused by unexpected events during its construction.

Should conditions not be favourable to constructing Conawapa for a 2026 ISD, a decision could be made as late as 2018 to displace Conawapa by other resources such as gas or to defer its ISD. Displacing Conawapa by an alternate resource would modify some of the benefits associated with the plan as described in this section; but this would be offset by the reduction in downside risk.

Provides the Highest Financial Benefit to the Province and to Manitobans

Given that Pathway 4 has a greater possibility of leading to an earlier Conawapa than Pathway 3, it has a greater possibility of the higher level of transfers to the Province in the form of provincial debt guarantee fees, water rentals and capital taxes.

Offers the Highest Level of Socio-economic Benefits to Manitobans

Given that Pathway 4 has a greater possibility of leading to an earlier Conawapa than Pathway 3, it has a greater possibility of the higher level of employment and provincial economic growth.

Provides the Most Beneficial Package of Socio-economic Impacts and Benefits to Northern and Aboriginal Communities

Given that Pathway 4 has a greater possibility of leading to an earlier Conawapa than Pathway 3, it has a greater possibility of training, employment, business opportunities, income sharing and participation in environmental and socio-economic protection.

Supports Manitoba's Clean Energy Strategy and Sustainable Development Principles

To a greater degree than Pathway 3, Pathway 4 supports Manitoba's Sustainable Development Principles by providing clean renewable energy, (e.g. reducing global GHG emissions by displacing thermal generation in Manitoba and to a larger degree in the export jurisdictions) and by providing an infrastructure legacy for future generations.

Attachment: <u>Preferred Plan and other plans in Pathways 4 & 5 with a New 750 MW Interconnection Protect Manitoba Domestic Customer Service Better than All Gas Plan or ones Without New Interconnections</u>

By having increased access to imports and by having increased domestic generation, the 750 MW Interconnection Plans provide the highest level of system reliability to address generation or major transmission outages or unexpectedly high load peaks, and the highest level of energy security to mitigate unexpectedly severe droughts or unexpectedly high energy consumption.

<u>System reliability - capacity</u>

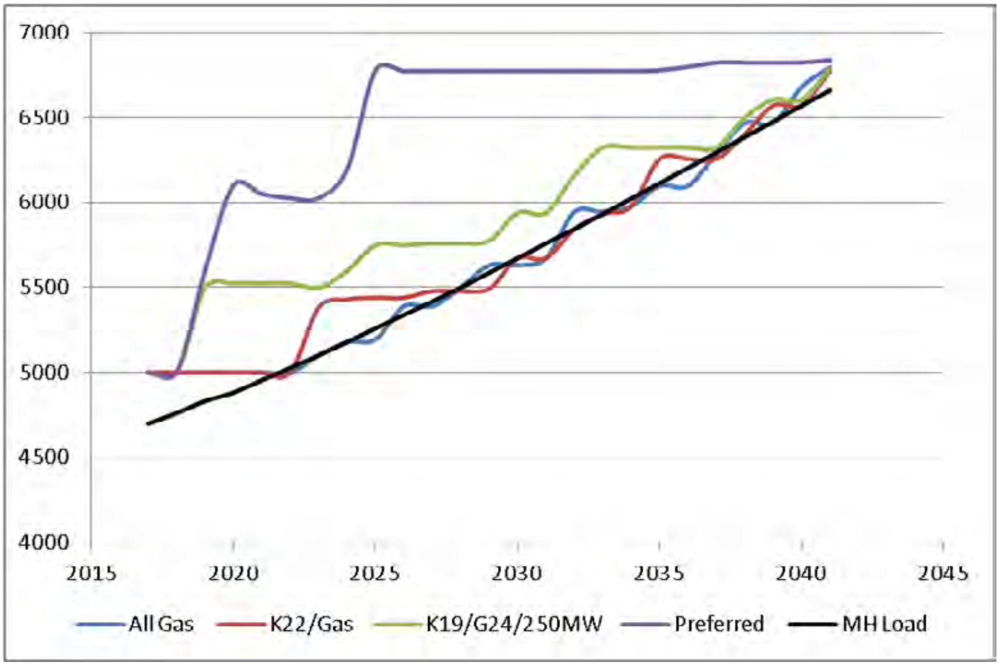
Over the 20 years starting with the 2019 Keeyask ISD, Pathways 4 and 5 provide up to 1,200 MW additional load carrying capacity to deal with equipment outages and load forecast uncertainty compared to the All Gas Plan and up to 900 MW more than the Keeyask 2022 Gas Plan.

Extract from Chapter 13 of NFAT Submission Showing Additional reliability with Preferred Plan compared to other plans.

Figure 1 (extract of Figures 13.2 from Submission) shows the estimated load-carrying capability of the Manitoba Hydro system with the preferred and alternative plans. As shown in the figure, the load-carrying capability of the Preferred Development Plan is significantly greater than the others. The interconnection combined with the additional hydro resources contributes to much higher reliability. For the same reason, though to a lesser extent, the alternative with the smaller interconnection and Keeyask G.S. has a greater load-carrying capability than the two alternatives without a new interconnection.

With greater reliability, customers could expect less failure of bulk supply and consequently less unserved load. While failures in bulk supply would be very infrequent, they can have major consequences.

FIGURE 1 (FIGURE 13.2 OF CHAPTER 13 OF NFAT) PEAK LOAD CARRYING CAPABILITY (MW)

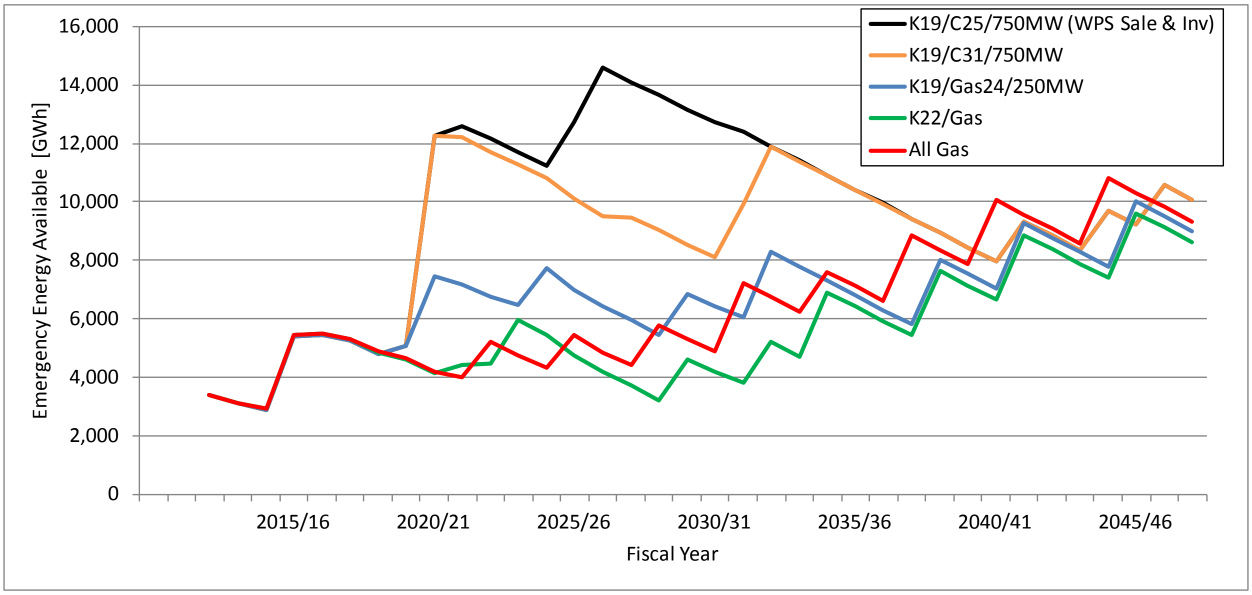


<u>System security – emergency energy</u>

Over the same 20-year period, should Manitoba experience a drought significantly more severe than experienced to date and/or planned for, the 750MW Interconnection Plans provide significant additional emergency energy imports to meet Manitoba domestic load compared to the All Gas Plan and compared to the Keeyask 2022 Gas Plan.

The following is extracted from the answer to NFAT Interrogatory MNP/MH I -0072.

Figure 2 Emergency Energy Available Including Non-Firm On-Peak Imports



The preferred plan is the line K19/C25/750 MW (WPS Sale & Investment in 750 MW Interconnection).

Figure 2 shows that the plan with Conawapa G.S. in 2031/32 provides, over the 20 year period starting with the 2019/20 Keeyask G.S. in-service date, an average of between approximately 3,000 GWh/year and 5,000 GWh/year more emergency energy compared to the All Gas, K22/Gas and K19/Gas24/250MW Plans. Alternatively when Conawapa is advanced in the Preferred Plan this range grows to average between approximately 4,500 GWh/year and 6,500 GWh/year.

In general, the two development plans that include the new 750MW interconnection and construction of Conawapa G.S. have more emergency energy available in the medium-term than the other plans, which generally include large quantities of new thermal generation. This difference narrows and, when including non-firm on-peak imports, all plans have similar emergency energy profiles beyond fiscal year 2039/40.

REFERENCE: Chapter 14: Conclusions; Section: 14.6.1; Page No.: 45

QUESTION:

Given Manitoba Hydro has not fully committed to an ISD for Conawapa, please provide all reasons it is pursuing the 750 MW interconnection with the US when"[c]ompared to Pathway 3, the Pathway 4 benefits are slightly higher, unless it is assumed that Conawapa will not be built for decades"

RESPONSE:

Please refer to response to LCA/MH I-037

REFERENCE: Chapter 14: Conclusions; Section: 14.5; Page No.: 30

QUESTION:

Regarding the potential for increasing import capacity for the 250 MW interconnection beyond current assumptions, please provide copies of all completed studies showing the transmission export potential from the 250 MW interconnection.

RESPONSE:

The potential for increasing import capacity for the 250 MW interconnection is discussed in Manitoba Hydro report number SPD 2013/05 titled Group Facility Study MHEM 1100/750/250 MW Export/Import Firm Point to Point Group Transmission Service Requests.

This report, which contains Commercially Sensitive Information (CSI), was made available to the Independent Expert Consultants (IECs) in response to PE/MH I-007.

This report was also provided as CSI as an attachment to Manitoba Hydro's response to PUB/MH I-134.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8-12

QUESTION:

For each consultant that produced an electricity price forecast considered for the "consensus based" forecast, please provide an excel spreadsheet with the reference, high, and low long-term 2012/2013 electricity price forecasts at MINN Hub. Where possible please provide capacity and peak and off-peak energy prices separately.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8-12

QUESTION:

For each consultant that produced an electricity price forecast considered for the "consensus based" forecast, please provide an excel spreadsheet with the reference, high, and low long-term Adjusted 2012/2013 electricity price forecasts at MINN Hub. Where possible please provide capacity and peak and off-peak energy prices separately.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8-12

QUESTION:

For each consultant that produced an electricity price forecast considered for the "consensus based" forecast, please provide an excel spreadsheet with the reference, high, and low long-term 2013/2014 electricity price forecasts at MINN Hub. Where possible please provide capacity and peak and off-peak energy prices separately.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 9

QUESTION:

For the "price adjustment from MINN Hub to the [Canada-US] border", please provide an excel spreadsheet with the adjustment used for the 2012/2013 consensus forecast, the adjusted 2012/2013 consensus forecast, and the 2013/2014 forecast.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 9

QUESTION:

For the "price adjustment from MINN Hub to the [Canada-US] border", please list what historical data was used to derive the adjustments used to create the 2012/2013 consensus forecast, the adjusted 2012/2013 consensus forecast, and the 2013/2014 forecast.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 9

QUESTION:

For the "price adjustment from MINN Hub to the [Canada-US] border", please provide all workpapers Manitoba-Hydro relied on to create the adjustments used to create the 2012/2013 consensus forecast, the adjusted 2012/2013 consensus forecast, and the 2013/2014 forecast. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1.1; Page No.: 10-11

QUESTION:

For each of the three products, On Peak All-in, On-Peak Long-Term Dependable, and Off-Peak Energy, please provide an excel spreadsheet with the 2012/2013 consensus forecast, the adjusted 2012/2013 consensus forecast, and the 2013/2014 forecast.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 41-43

QUESTION:

Was any coal price uncertainty accounted for in the probabilistic analysis of energy prices? If so, please describe how coal price uncertainty impacted electricity price variation. If not, why not?

RESPONSE:

Coal price uncertainty was not directly accounted for in the Energy Prices factor of the probabilistic analysis. The Energy Prices factor included the variables of natural gas prices and electricity prices.

Coal price uncertainty was indirectly accounted for in the probabilistic analysis since the impact of the cost to generate electricity in MISO, including coal-fired generation, is embedded in the electricity price variable.

Please also refer to Manitoba Hydro's response to LCA/MH I-049.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 41; Chapter 3: Trends and Factors Influencing North American Electricity Supply, Section 3.4.4, page 33

QUESTION:

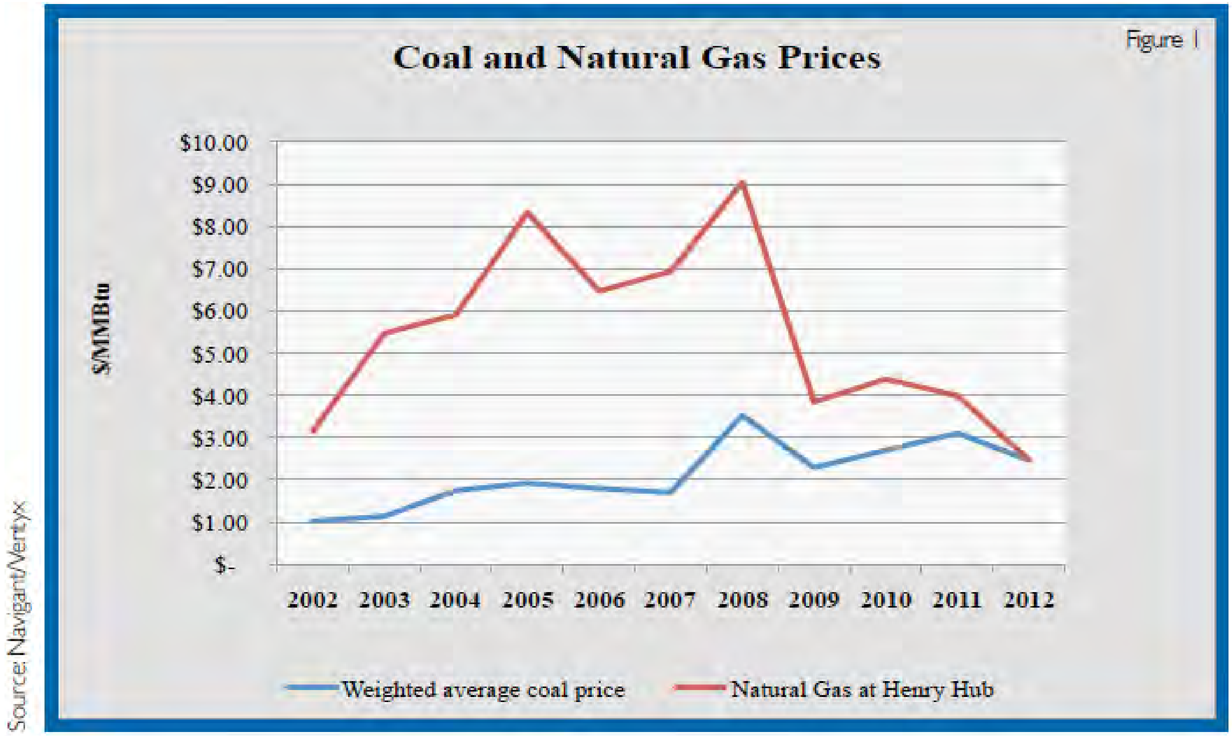
Manitoba Hydro states in Appendix 9.3 that "natural gas is typically 'on the margin'", while in Chapter 3, Manitoba Hydro states that for MISO "coal is the marginal or price setting fuel the majority of the time". How does the probabilistic analysis account for the fact that changes in MISO electricity prices may not always be sensitive to changes in natural gas prices?

RESPONSE:

The reference, high and low forecasts used in the probabilistic analysis take into account both changes in natural gas prices and coal prices. Since natural gas prices peaked in 2008, lower natural gas prices have at times and to varying degrees resulted in the displacement of coal generation by natural gas generation in some regions. For example, in the spring of 2012, the lowest natural gas prices in about a decade resulted in short-term coal to natural gas fuel switching in eastern regions which resulted in an estimated increase natural gas consumption of 6 billion cubic feet per day during the first half of 2012[1].

This fuel price competition since 2008 has resulted in natural gas prices putting downward pressure on coal prices and making coal prices sensitive to natural gas prices, as can be seen in Figure 1 from The Phenomenon of Coal-to-Gas Switching article.

[1] See The Phenomenon of Coal-to-Gas Switching, by Gordon Pickering and others, Western Energy, Fall 2012. http://www.navigant.com/~/media/WWW/Site/Insights/Energy/The%20Phenomenon%20of%20CoaltoGas%20Switching%20by%20GPickeringWEI%20articlepdf.ashx



While weather and seasonal load variations have a definite impact on short-term market prices, natural gas prices are the major driver of overall MISO on peak power prices and a review of the price forecast consultant work suggests that this will continue on into the future when even more natural gas-fired generation is expected in the MISO market.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 41

QUESTION:

When estimating carbon price impacts on electricity prices, what assumptions does Manitoba Hydro use about what fuel is setting the marginal price, as coal is more sensitive to carbon pricing than gas?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 42

QUESTION:

Please provide workpapers relied upon to create the electricity prices calculated deterministically from the gas and carbon values in each scenario of the nine-branch distribution. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 42

QUESTION:

Please provide workpapers relied upon to benchmark Manitoba Hydro's pre-existing gas, carbon, and electricity price scenarios to the nine-branch distribution. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 43

QUESTION:

Please provide workpapers and calculations relied upon to calculate the mean and variance of the levelized electricity price of 22.3 and 45.6. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 43

QUESTION:

Please provide workpapers and calculations relied upon to assign the probabilities shown in Figure 2.4. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 43

QUESTION:

Please provide workpapers and calculations relied upon to calculate the mean and variance of the levelized electricity price of 22.1 and 47.7. Where possible please provide these workpapers in machine-readable electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8-12

QUESTION:

How are exports to markets other than MISO, such as Ontario and Saskatchewan, quantified and priced for modeling purposes?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8-12

QUESTION:

Please provide all electricity price forecasts for Ontario and Saskatchewan relied upon for creation of the NFAT submission.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

For each of the mitigation provisions listed in section 15.2.2.1, please identify any used to successfully mitigate the problems with drought during the 2003/04 Manitoba Hydro fiscal year and how the provision provided benefits to Manitoba Hydro and its ratepayers during this time.

RESPONSE:

As referenced in Section 15.2.2.1, pages 8-11, Manitoba Hydro's current long-term contracts contain numerous provisions that are designed to mitigate the risks associated with these contracts. These provisions are designed for current market conditions which did not exist during the drought of 2003/04.

Market Access

The market access provisions referenced were not available during the 2003/04 Manitoba Hydro fiscal year as this drought was prior to the MISO market being established in 2005. These provisions are intended to improve Manitoba Hydro's market access for surplus energy sales, not to mitigate the impact of drought. Under drought conditions, Manitoba Hydro does not have energy surpluses and therefore does not need additional market access.

Curtailments and Curtailment Priority Criteria

The curtailment provisions referenced were not used to mitigate supply problems associated with drought during 2003/04 as sufficient resources were always available to serve Manitoba load without having to resort to curtailing export sales.

Alternative Supply

The alternative supply provisions referenced were not available during 2003/04 as this drought was prior to the MISO market being established in 2005. Manitoba Hydro did have the right to supply contracts via third party energy purchases during the 2003/04 period however for US export contracts these purchases would have to occur at the Canada-US border as Manitoba Hydro did not have FERC Power Marketers Authorization to buy and re-sell electricity in the U.S. As a result Manitoba Hydro could only buy down any sale obligation with an offsetting purchase.

Adverse Water Conditions

The Adverse Water Conditions provisions referenced were not used to mitigate the drought during the 2003/04 Manitoba Hydro fiscal year. Current provisions allow Manitoba Hydro to reduce its sale obligations whereas in the drought of 2003/04 the then Adverse Water clauses in contacts provided Manitoba Hydro with access to cost based energy. During the drought Manitoba Hydro was able to purchase other energy without exercising any adverse water rights it had under contract at the time.

Creditworthiness

Creditworthiness provisions were not used to mitigate the problems with drought during the 2003/04 Manitoba Hydro fiscal year. During droughts Manitoba Hydro is not exporting, rather it is a net importer and as such the credit risk resides with the seller not Manitoba Hydro.

Conditions and Options

Conditions and Options provisions were not used to mitigate the problems with drought during the 2003/04 Manitoba Hydro fiscal year. These provisions allow for potential delays in the start of the sale or termination of the sale in the event that new generation or transmission facilities are delayed or not built. Drought would not quality as a valid reason for a delay or termination of a sale under the Conditions and Options provisions.

Conditions Precedent

Conditions Precedent provisions were not used to mitigate the problems with drought during the 2003/04 Manitoba Hydro fiscal year. These provisions ensure that Manitoba Hydro sales obligations do not take effect unless key conditions are met and all required approvals are granted. Drought conditions would not apply to these provisions.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2.1; Page No.: 8-11

QUESTION:

Please describe all lessons learned from the experience during the 2003/2004 Manitoba Hydro fiscal year drought that were incorporated into the mitigation provisions listed in Section 15.2.2.1.

RESPONSE:

The electricity market has evolved from a bilateral energy market to an open liquid market including provisions for independent financial settlement since the 2003/2004 drought. Manitoba Hydro now is in a significantly different and better position to manage the situation should the water supplies and market prices of 2003/2004 repeat in the future.

When the MISO energy market opened in 2005, Manitoba Hydro amended all its legacy long-term contracts to allow MH to use market mechanisms to financially settle its obligations to its customers. In other words, Manitoba Hydro has the option to serve its long-term contracts from its own generation resources or purchase energy from the MISO market to satisfy its contract commitments. In the drought of 2003/04 it did not have that option.

In addition, since 2003/2004, Manitoba Hydro has acquired the rights to all northbound firm point-to-point MISO transmission service between the U.S. and Manitoba. This transmission acquisition has reduced Manitoba Hydro’s exposure to captive transactions and captive pricing tactics utilized by its counterparties during the drought.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 20

QUESTION:

Please provide a the projected annual capital expenditures for Manitoba Hydro's portion of the 750 MW transmission interconnection assumed for the preferred development plan where WPS is assumed to have made an investment in U.S. transmission facilities.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 20

QUESTION:

Please provide a the projected annual capital expenditures for Manitoba Hydro's portion of the 750 MW transmission interconnection assumed for the plans where WPS is assumed not to have made an investment in U.S. transmission facilities (e.g. Plan 15).

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.3; Page No.: 14

QUESTION:

Please provide an update of Table 10.4 showing a new development plan that is the same as Plan 14, except without the assumption of the WPS investment in the new transmission interconnection. Instead use the assumption from Plan 15 where Manitoba Hydro is assumed to invest additional capital in new transmission. Continue to include the WPS sale.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix I Manitoba Hydro Electric Board Annual report (2011/2012); Section: Risk Management; Page No.: 52

QUESTION:

Please provide a copy of the most recent corporate plan in place to mitigate the impact of drought.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Model Capabilities; Page No.: 2

QUESTION:

Does the SPLASH model assume a perfect forecast of water inflow for each window for production costing purposes? If not, how does it incorporate uncertainty in water flow?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Opportunity Market Transactions; Page No.: 6

QUESTION:

Does the SPLASH model assume perfect foresight of power prices within an optimization window? If not, how does it incorporate uncertainty in power prices?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Model Capabilities; Page No.: 2

QUESTION:

In optimizing within each window, does the SPLASH model incorporate any knowledge of future windows?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Model Capabilities; Page No.: 2

QUESTION:

Please provide the windows and time steps used for the SPLASH model 35 year planning horizon.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Domestic Load; Page No.: 3

QUESTION:

Please provide the monthly on peak and off peak net Manitoba load forecast input into SPLASH for the 2012 analysis and the 2013 update. Include all separate forecasts for load sensitivities

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Hydro Generation; Page No.: 4

QUESTION:

Please provide a SPLASH system diagram showing the configuration of reservoirs, rivers, and hydro-electric generation sources for the system without Keeyask or Conawapa, with only Keeyask added and with only Conawapa added.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Hydro Generation; Page No.: 4

QUESTION:

Are maintenance and forced outages randomly assigned throughout each time window in the SPLASH model or are they directly input?

RESPONSE:

Maintenance and forced outages are directly input into the SPLASH model.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Hydro Generation; Page No.: 4

QUESTION:

Do water rental costs impact the SPLASH simulation optimization of hydro resources? If so, how?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Hydro Generation; Page No.: 4

QUESTION:

Please provide all water rental assumptions in the SPLASH model.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Please provide the assumed maximum and minimum output of each thermal station modeled with SPLASH.

RESPONSE:

An attachment has been provided in response to this information request. The attachment contains the thermal generation performance assumptions used in the SPLASH model for each new and existing thermal station.

Brandon Unit 5 Coal-Fired Steam Turbine Generator
Monthly Unit Characteristics - Unrestricted Emergency Operations

						Outages					
Month	# of Days	Temp. oC	Net Heat Rate	Gross Plant Output MW		Planned Mainten	Forced Outage	License Restric	Net plant energy GW.h (mature peak)		Minimum Generation
			BTU/kW.h (HHV)	@ South	@ North	(#days / month)	(% / month)	(% of plant)	@ South	@ North	GW.h
JAN	31	-18.1	11829	105.5	116.1		5.0%		68.3	75.2	15.48
FEB	28.25	-14.7	11829	105.5	116.1		5.0%		62.3	68.5	15.46
MAR	31	-7.1	11805	105.5	116.1		5.0%		68.3	75.2	10.94
APR	30	3.7	11805	105.5	116.1	23.0	5.0%		15.4	17.0	8.42
MAY	31	11.4	11805	105.5	116.1	7.0	5.0%		52.9	58.2	8.41
JUN	30	16.7	11964	104.9	115.4		5.0%		65.8	72.3	9.43
JUL	31	19.2	12177	104.1	114.5		5.0%		67.4	74.2	10.42
AUG	31	18.0	12097	104.4	114.8		5.0%		67.6	74.4	10.42
SEP	30	11.8	11805	105.5	116.1		5.0%		66.1	72.8	9.43
OCT	31	5.4	11805	105.5	116.1		5.0%		68.3	75.2	8.41
NOV	30	-5.1	11805	105.5	116.1		5.0%		66.1	72.8	8.42
DEC	31	-14.7	11829	105.5	116.1		5.0%		68.3	75.2	10.94
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	Total
	365.25	2.2	11880	105.2	115.8	30.0			737	811	126.17

Conversion to North 10%

Availability	
Overall	89.5%

Brandon Units #6 & 7 Simple Cycle Gas Turbines
Monthly Unit Characteristics

Month	# of Days	Temp. oC	Net Heat Rate BTU/kW.h (HHV)	Gross Plant Output MW		Outages: Planned Mainten (#days / month)	Outages: Forced Outage (% / month)	Outages: License Restric (% of plant)	Net plant energy GW.h (mature peak		Minimum Generation GW.h
				@ South	@ North				@ South	@ North	
JAN	31	-18.1	12151	**279.5**	**307.4**		**1.5%**		**203.8**	**224.2**	2.16
FEB	28.25	-14.7	12158	**279.5**	**307.4**		**1.5%**		**185.7**	**204.3**	1.79
MAR	31	-7.1	12177	**279.5**	**307.4**		**1.5%**		**203.8**	**224.2**	2.16
APR	30	3.7	12203	**274.7**	**302.2**	**5.0**	**1.5%**		**161.5**	**177.7**	2.02
MAY	31	11.4	12282	**260.3**	**286.3**		**1.5%**		**189.8**	**208.8**	2.16
JUN	30	16.7	12336	**240.3**	**264.3**		**1.5%**		**169.5**	**186.5**	2.02
JUL	31	19.2	12373	**233.7**	**257.1**		**1.5%**		**170.4**	**187.5**	2.16
AUG	31	18.0	12349	**236.2**	**259.9**		**1.5%**		**172.3**	**189.5**	2.16
SEP	30	11.8	12269	**242.1**	**266.3**	**15.0**	**1.5%**		**85.4**	**94.0**	2.02
OCT	31	5.4	12227	**269.8**	**296.8**		**1.5%**		**196.7**	**216.4**	2.16
NOV	30	-5.1	12170	**279.5**	**307.4**		**1.5%**		**197.2**	**216.9**	2.02
DEC	31	-14.7	12158	**279.5**	**307.4**		**1.5%**		**203.8**	**224.2**	2.16
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	**Total**
	365.25	2.2	12238	**262.9**	**289.2**	**20.0**			**2140**	**2354**	**25.01**

Conversion to North **10%**

Availability	
Overall	**93.3%**

Selkirk Units 1 & 2 Gas-Fired Steam Turbine Generators - Without Cooling Tower
Average Monthly Unit Characteristics - Cooks Creek Temperature Limited

(Performance based on once-through cooling as per the 2005 EIS for License 1645 R5. License Restrictions as per Appendix D of same license.)

						Outages					
Month	# of Days	Temp. oC	Net Heat Rate	Gross Plant Output MW		Planned Mainten	Forced Outage	License Restric	Net plant energy GW.h (mature peak)		Minimum Generation
			BTU/kW.h (HHV)	@ South	@ North	(#days / month)	(% / month)	(% of plant)	@ South	@ North	GW.h
JAN	31	-18.1	12154	132.0	145.2		5.0%		89.3	98.3	1.75
FEB	28.25	-14.7	12154	132.0	145.2		5.0%		81.4	89.6	1.45
MAR	31	-7.1	12154	132.0	145.2		5.0%		89.3	98.3	1.75
APR	30	3.7	12154	132.0	145.2		5.0%	22.1%	67.4	74.1	1.64
MAY	31	11.4	12154	132.0	145.2		5.0%	57.8%	37.7	41.5	1.75
JUN	30	16.7	12154	132.0	145.2		5.0%	50.0%	43.2	47.6	1.64
JUL	31	19.2	12154	132.0	145.2		5.0%	6.9%	83.2	91.5	1.75
AUG	31	18.0	12154	132.0	145.2		5.0%	5.3%	84.6	93.1	1.75
SEP	30	11.8	12154	132.0	145.2	21.0	5.0%	0.1%	25.9	28.5	1.64
OCT	31	5.4	12154	132.0	145.2		5.0%	1.0%	88.4	97.3	1.75
NOV	30	-5.1	12154	132.0	145.2		5.0%		86.5	95.1	1.64
DEC	31	-14.7	12154	132.0	145.2		5.0%		89.3	98.3	1.75
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	Total
	365.25	2.2	12154	132.0	145.2	21.0			866	953	20.25

Conversion to North 10%

Availability	
Overall	78.2%

GE 7FA Simple Cycle Gas Turbine
Monthly Unit Characteristics

Month	# of Days	Temp. oC	Net Heat Rate BTU/kW.h (HHV)	Net Plant Output MW @ South	Net Plant Output MW @ North	Outages: Planned Mainten (#days / month)	Outages: Forced Outage (% / month)	Outages: License Restric (% of plant)	Net plant energy GW.h (mature peak) @ South	Net plant energy GW.h (mature peak) @ North	Minimum Generation GW.h
JAN	31	-18.1	9861	222.8	245.0		3.5%		158.8	174.7	17.47
FEB	28.25	-14.7	9873	220.8	242.9		3.5%		143.5	157.8	15.78
MAR	31	-7.1	9888	217.1	238.8		3.5%		154.8	170.2	0.00
APR	30	3.7	9917	209.1	230.0		3.5%		144.3	158.7	0.00
MAY	31	11.4	9973	201.8	222.0		3.5%		143.9	158.3	0.00
JUN	30	16.7	10030	196.9	216.6		3.5%		135.9	149.4	14.95
JUL	31	19.2	10067	194.8	214.3		3.5%		138.9	152.8	15.28
AUG	31	18.0	10046	196.0	215.6		3.5%		139.8	153.7	15.37
SEP	30	11.8	9977	201.5	221.6	14.0	3.5%		74.1	81.5	0.00
OCT	31	5.4	9927	207.4	228.2		3.5%		147.9	162.7	0.00
NOV	30	-5.1	9893	215.7	237.2		3.5%		148.8	163.7	0.00
DEC	31	-14.7	9873	220.8	242.9		3.5%		157.4	173.2	17.32
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	**Total**
	365.25	2.2	9944	208.7	229.6	14.0			1688	1857	**96.17**

Conversion to North 10%

Availability	
Overall	92.3%

GE 7FA Combined Cycle Gas Turbine
Monthly Unit Characteristics

Month	# of Days	Temp. oC	Net Heat Rate	Net Plant Output MW		Outages			Net plant energy GW.h (mature peak)		Minimum Generation
						Planned Mainten	Forced Outage	License Restric			
			BTU/kW.h (HHV)	@ South	@ North	(#days / month)	(% / month)	(% of plant)	@ South	@ North	GW.h
JAN	31	-18.1	6707	324.6	357.0		3.5%		228.4	251.2	8.29
FEB	28.25	-14.7	6699	322.4	354.6		3.5%		206.7	227.4	7.51
MAR	31	-7.1	6675	318.5	350.4		3.5%		224.1	246.5	8.13
APR	30	3.7	6652	309.3	340.3		3.5%		210.6	231.7	7.65
MAY	31	11.4	6660	300.5	330.5		3.5%		211.4	232.6	7.67
JUN	30	16.7	6682	293.8	323.2		3.5%		200.0	220.0	7.26
JUL	31	19.2	6701	290.9	320.0		3.5%		204.7	225.1	7.43
AUG	31	18.0	6690	292.6	321.8		3.5%		205.8	226.4	7.47
SEP	30	11.8	6661	300.0	330.0	14.0	3.5%		108.9	119.8	3.95
OCT	31	5.4	6651	307.9	338.7		3.5%		216.6	238.3	7.86
NOV	30	-5.1	6669	316.9	348.6		3.5%		215.8	237.4	7.83
DEC	31	-14.7	6699	322.4	354.6		3.5%		226.8	249.5	8.24
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	**Total**
	365.25	2.2	6679	308.3	339.1	14.0			2460	2706	**89.29**

Conversion to North 10%

Availability	
Overall	91.0%

GE LM6000PH Simple Cycle Aeroderivative Gas Turbine
Monthly Unit Characteristics

Month	# of Days	Temp. oC	Net Heat Rate	Gross Plant Output MW		Outages Planned Mainten	Outages Forced Outage	Outages License Restric	Net plant energy GW.h (mature peak)		Minimum Generation
			BTU/kW.h (HHV)	@ South	@ North	(#days / month)	(% / month)	(% of plant)	@ South	@ North	GW.h
JAN	31	-18.1	9293.0	50.3	55.3		1.5%		36.7	40.4	4.03
FEB	28.25	-14.7	9281.0	50.4	55.4		1.5%		33.5	36.8	3.68
MAR	31	-7.1	9292.0	49.4	54.3		1.5%		36.0	39.6	0.00
APR	30	3.7	9502.0	46.2	50.8		1.5%		32.6	35.8	0.00
MAY	31	11.4	9505.0	45.6	50.1		1.5%		33.2	36.6	0.00
JUN	30	16.7	9557.0	43.6	48.0		1.5%		30.8	33.9	3.38
JUL	31	19.2	9627.0	42.4	46.6		1.5%		30.9	34.0	3.40
AUG	31	18.0	9584.0	43.1	47.4		1.5%		31.4	34.6	3.46
SEP	30	11.8	9507.0	45.5	50.0	15.0	1.5%		16.0	17.6	0.00
OCT	31	5.4	9436.0	47.5	52.2		1.5%		34.6	38.1	0.00
NOV	30	-5.1	9322.0	48.8	53.7		1.5%		34.5	37.9	0.00
DEC	31	-14.7	9281.0	50.4	55.4		1.5%		36.7	40.4	4.04
	Total Days	AvgAnTemp	Avg Heat Rate	Average MW	Average MW	Total Outage Days			Total Annual GW.h	Total Annual GW.h	**Total**
	365.25	2.2	9432	46.9	51.6	15.0			387	426	**22.00**

Conversion to North 10%

Availability	
Overall	94.5%

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Is the maximum output of the thermal units in SPLASH reduced for forced outages, planned maintenance and license restrictions in all time steps? If not, please describe how these are modeled.

RESPONSE:

Please see response to LCA/MH I-085.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Please provide the assumed reduction in maximum generation for each thermal station modeled with SPLASH due to forced outages.

RESPONSE:

Please see response to LCA/MH I-085.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Please provide the assumed reduction in maximum generation for each thermal station modeled with SPLASH due to planned maintenance.

RESPONSE:

Please see response to LCA/MH I-085.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Please provide the assumed reduction in maximum generation for each thermal station modeled with SPLASH due to license restrictions.

RESPONSE:

Please see response to LCA/MH I-085.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Opportunity Market Transactions; Page No.: 6

QUESTION:

Are there any limitations to the total export or import opportunity market in the SPLASH model other than transmission related constraints? If so, please provide the assumed constraints.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Opportunity Market Transactions; Page No.: 6

QUESTION:

Does SPLASH model exports or imports as price blocks at a certain fixed volume? If so please provide the assumed block volumes.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Opportunity Market Transactions; Page No.: 6

QUESTION:

Please provide the assumed monthly on peak and off peak export and import price-volume relationships used for each time step in the SPLASH model for reference, high and low price cases for the 2012 analysis and the 2013 update analysis.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Opportunity Market Transactions; Page No.: 6

QUESTION:

Explain how firm imports or exports influence the price-volume relationships used to model opportunity sales in the SPLASH model, if at all.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Hydro Generation; Page No.: 4

QUESTION:

How are historical monthly inflows modified to reflect current regulation for SPLASH modeling purposes?

RESPONSE:

Streamflow records for the Nelson-Churchill watershed have been adjusted to reflect present-use conditions and account for the development of major reservoirs, construction of river diversions, and modifications to regulation patterns.

Regulated inflows of the Nelson-Churchill watershed represent streamflow from the Winnipeg River, Saskatchewan River, and Churchill River. The modifications applied to the historic record were developed though several provincial and federal studies, including the Saskatchewan-Nelson Basin Board, the Churchill River Study, and subsequent studies by Manitoba Water Resources Branch. Streamflow modifications in these studies were developed by implemented regulation models to generate naturalized streamflow records and re-regulated inflows to present-use.

Modifications to the streamflow record for adjustment to present-use are summarized as follows:

- Winnipeg River – Earlier flows are adjusted to account for Lake St. Joseph Diversion and present-day regulation patterns.
- Saskatchewan River – Adjustments made to account for major water uses, including the St. Mary's Diversion in Alberta, Brazeau Dam and Gardiner Dam hydroelectric projects,

and others projects. Adjustments are also made in SPLASH to account for changes in consumptive use and present-day regulation patterns.

- Churchill River – Adjustments made to account for changes to Island Falls GS regulation patterns. Early portions of the streamflow record are reconstructed based on available hydroclimatic data.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Domestic Load; Page No.: 3

QUESTION:

Is peak MW of domestic load input in SPLASH or just energy requirements? If peak load is modeled, please describe how the generation is dispatched to meet this peak load and how this would impact production costs and export revenues.

RESPONSE:

Domestic load energy requirements only and not peak MW are input into the SPLASH model.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Non-Hydro Generation; Page No.: 5

QUESTION:

Please provide the assumed heat rates for all thermal generating units modeled in SPLASH.

RESPONSE:

Please see response to LCA/MH I-085.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6;

http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_74-Attachment_2.pdf; p. 8

QUESTION:

Please provide the total maximum amount of import energy available at each time step in the SPLASH simulation through the critical flow period.

RESPONSE:

The following tables breakdown the maximum amount of import energy available into monthly on-peak and off-peak values for each of the 15 development plans studied.

Plan 1 - All Gas

Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	214	369	4	179	4	173	4	179	4	179	4	173	4	179	214	369	221	381	221	381	202	347	221	381	**4611**
2022/23	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2023/24	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2024/25	189	350	4	134	4	129	4	134	4	134	4	129	4	134	189	350	195	362	195	362	178	330	195	362	**4075**
2025/26	186	348	39	282	37	273	39	282	39	282	37	273	39	282	37	273	39	282	39	282	35	257	39	282	**3997**
2026/27	49	280	50	289	49	280	50	289	50	289	49	280	50	289	49	280	50	289	50	289	46	263	50	289	**3995**
2027/28	80	303	83	313	80	303	83	313	83	313	80	303	83	313	80	303	83	313	83	313	75	285	83	313	**4662**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	55	284	57	294	55	284	57	294	57	294	55	284	57	294	55	284	57	294	57	294	52	268	57	294	**4130**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	70	295	72	305	70	295	72	305	72	305	70	295	72	305	70	295	72	305	72	305	66	278	72	305	**4446**
2037/38	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2038/39	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2039/40	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2040/41	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2043/44	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2044/45	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2045/46	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2046/47	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2047/48	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**

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Plan 2 - K22/Gas
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	217	371	4	185	4	179	4	185	4	185	4	179	4	185	217	371	225	384	225	384	205	350	225	384	**4679**
2022/23	190	351	4	135	4	131	4	135	4	135	4	131	4	135	190	351	196	362	196	362	179	330	196	362	**4093**
2023/24	186	348	4	129	10	130	11	134	11	134	10	130	11	134	196	350	202	362	202	362	184	330	202	362	**4134**
2024/25	196	350	11	134	10	130	11	134	11	134	10	130	11	134	196	350	202	362	202	362	184	330	202	362	**4157**
2025/26	196	350	50	285	48	275	50	285	50	285	48	275	50	285	48	275	50	285	50	285	45	259	50	285	**4159**
2026/27	55	286	57	295	55	286	57	295	57	295	55	286	57	295	55	286	57	295	57	295	52	269	57	295	**4157**
2027/28	55	286	57	295	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4041**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	55	284	57	294	55	284	57	294	57	294	55	284	57	294	55	284	57	294	57	294	52	268	57	294	**4130**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	61	289	63	299	61	289	63	299	63	299	61	289	63	299	61	289	63	299	63	299	58	272	63	299	**4264**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2037/38	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2038/39	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2039/40	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2040/41	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2043/44	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2044/45	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2045/46	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2046/47	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2047/48	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**

Plan 3 - Wind/Gas
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	214	369	4	179	4	173	4	179	4	179	4	173	4	179	214	369	221	381	221	381	202	347	221	381	**4611**
2022/23	211	366	4	173	4	167	4	173	4	173	4	167	4	173	211	366	218	379	218	379	198	345	218	379	**4537**
2023/24	211	366	4	173	4	167	4	173	4	173	4	167	4	173	211	366	218	378	218	378	198	345	218	378	**4535**
2024/25	215	370	4	181	4	175	4	181	4	181	4	175	4	181	215	370	222	382	222	382	203	348	222	382	**4629**
2025/26	201	359	53	293	51	283	53	293	53	293	51	283	53	293	51	283	53	293	53	293	48	267	53	293	**4298**
2026/27	63	290	65	300	63	290	65	300	65	300	63	290	65	300	63	290	65	300	65	300	59	273	65	300	**4302**
2027/28	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	58	286	60	296	58	286	60	296	60	296	58	286	60	296	58	286	60	296	60	296	54	270	60	296	**4191**
2033/34	70	295	72	305	70	295	72	305	72	305	70	295	72	305	70	295	72	305	72	305	66	278	72	305	**4446**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2037/38	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2038/39	54	283	55	293	54	283	55	293	55	293	54	283	55	293	54	283	55	293	55	293	50	267	55	293	**4099**
2039/40	69	294	71	304	69	294	71	304	71	304	69	294	71	304	69	294	71	304	71	304	65	277	71	304	**4419**
2040/41	79	303	82	313	79	303	82	313	82	313	79	303	82	313	79	303	82	313	82	313	75	285	82	313	**4650**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2043/44	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2044/45	53	283	54	292	53	283	54	292	54	292	53	283	54	292	53	283	54	292	54	292	50	266	54	292	**4081**
2045/46	63	291	65	300	63	291	65	300	65	300	63	291	65	300	63	291	65	300	65	300	60	274	65	300	**4308**
2046/47	78	301	81	312	78	301	81	312	81	312	78	301	81	312	78	301	81	312	81	312	73	284	81	312	**4620**
2047/48	73	297	75	307	73	297	75	307	75	307	73	297	75	307	73	297	75	307	75	307	68	280	75	307	**4506**

Plan 4 - K19/Gas24/250MW
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	169	4	175	4	175	4	169	4	175	186	393	193	406	193	406	176	370	193	406	**4470**
2021/22	186	393	4	175	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4675**
2022/23	196	395	11	180	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4699**
2023/24	214	409	11	214	10	207	11	214	11	214	10	207	11	214	214	409	222	422	222	422	202	385	222	422	**5099**
2024/25	196	395	11	180	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4699**
2025/26	196	395	50	331	48	320	50	331	50	331	48	320	50	331	48	320	50	331	50	331	45	301	50	331	**4701**
2026/27	55	330	57	341	55	330	57	341	57	341	55	330	57	341	55	330	57	341	57	341	52	311	57	341	**4699**
2027/28	55	330	57	341	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4583**
2028/29	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2029/30	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2030/31	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2031/32	60	332	62	343	60	332	62	343	62	343	60	332	62	343	60	332	62	343	62	343	56	313	62	343	**4775**
2032/33	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2033/34	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2034/35	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2035/36	50	339	51	351	41	304	42	314	42	314	41	304	42	314	41	304	42	314	42	314	39	286	42	314	**4286**
2036/37	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2037/38	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2038/39	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2039/40	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2040/41	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2041/42	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2042/43	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2043/44	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2044/45	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2045/46	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2046/47	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2047/48	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**

Plan 5 - K19/Gas25/750MW (WPS Sale & Inv)
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	187	348	4	130	45	241	47	249	47	249	45	241	47	249	228	464	236	479	236	479	215	437	236	479	**5618**
2021/22	228	464	47	249	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6054**
2022/23	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2023/24	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2024/25	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2025/26	246	544	72	417	69	404	72	417	72	417	69	404	72	417	69	404	72	417	72	417	65	380	72	417	**6079**
2026/27	69	399	71	412	95	432	98	446	98	446	95	432	98	446	95	432	98	446	98	446	90	407	98	446	**6297**
2027/28	92	431	95	445	100	457	103	472	103	472	100	457	103	472	100	457	103	472	103	472	94	430	103	472	**6706**
2028/29	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2029/30	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2030/31	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2031/32	99	434	103	449	99	434	103	449	103	449	99	434	103	449	99	434	103	449	103	449	94	409	103	449	**6498**
2032/33	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2033/34	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2034/35	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
2035/36	107	486	110	502	70	409	72	423	72	423	70	409	72	423	70	409	72	423	72	423	66	385	72	423	**6060**
2036/37	72	432	75	447	28	340	29	351	29	351	28	340	29	351	28	340	29	351	29	351	26	320	29	351	**4752**
2037/38	28	341	29	353	28	341	29	353	29	353	28	341	29	353	28	341	29	353	29	353	26	321	29	353	**4495**
2038/39	28	373	29	386	28	373	29	386	29	386	28	373	29	386	28	373	29	386	29	386	27	351	29	386	**4887**
2039/40	29	348	30	360	29	348	30	360	30	360	29	348	30	360	29	348	30	360	30	360	27	328	30	360	**4588**
2040/41	29	352	30	363	29	352	30	363	30	363	29	352	30	363	29	352	30	363	30	363	27	331	30	363	**4634**
2041/42	29	360	30	372	29	360	30	372	30	372	29	360	30	372	29	360	30	372	30	372	28	339	30	372	**4743**
2042/43	30	358	31	370	30	358	31	370	31	370	30	358	31	370	30	358	31	370	31	370	28	337	31	370	**4726**
2043/44	30	362	31	374	30	362	31	374	31	374	30	362	31	374	30	362	31	374	31	374	28	341	31	374	**4773**
2044/45	31	365	32	377	31	365	32	377	32	377	31	365	32	377	31	365	32	377	32	377	29	344	32	377	**4819**
2045/46	31	369	32	381	31	369	32	381	32	381	31	369	32	381	31	369	32	381	32	381	29	347	32	381	**4865**
2046/47	31	372	32	384	31	372	32	384	32	384	31	372	32	384	31	372	32	384	32	384	30	350	32	384	**4911**
2047/48	32	393	33	406	32	393	33	406	33	406	32	393	33	406	32	393	33	406	33	406	30	370	33	406	**5167**

Plan 6 - K19/Gas31/750MW
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	187	348	4	130	45	241	47	249	47	249	45	241	47	249	228	464	236	479	236	479	215	437	236	479	**5618**
2021/22	228	464	47	249	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6054**
2022/23	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2023/24	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2024/25	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2025/26	247	547	72	422	70	409	72	422	72	422	70	409	72	422	70	409	72	422	72	422	66	385	72	422	**6141**
2026/27	73	438	76	453	73	438	76	453	76	453	73	438	76	453	73	438	76	453	76	453	69	412	76	453	**6223**
2027/28	70	414	73	428	64	409	66	423	66	423	64	409	66	423	64	409	66	423	66	423	60	385	66	423	**5786**
2028/29	64	414	67	427	64	414	67	427	67	427	64	414	67	427	64	414	67	427	67	427	61	390	67	427	**5821**
2029/30	66	424	68	438	66	424	68	438	68	438	66	424	68	438	66	424	68	438	68	438	62	399	68	438	**5959**
2030/31	66	450	69	465	66	450	69	465	69	465	66	450	69	465	66	450	69	465	69	465	62	424	69	465	**6290**
2031/32	64	407	66	421	64	407	66	421	66	421	64	407	66	421	64	407	66	421	66	421	60	383	66	421	**5733**
2032/33	64	410	66	424	64	410	66	424	66	424	64	410	66	424	64	410	66	424	66	424	60	387	66	424	**5778**
2033/34	64	414	67	428	64	414	67	428	67	428	64	414	67	428	64	414	67	428	67	428	61	390	67	428	**5825**
2034/35	65	444	67	459	65	444	67	459	67	459	65	444	67	459	65	444	67	459	67	459	61	418	67	459	**6199**
2035/36	64	413	67	427	27	336	28	347	28	347	27	336	28	347	27	336	28	347	28	347	26	316	28	347	**4656**
2036/37	28	338	28	349	28	338	28	349	28	349	28	338	28	349	28	338	28	349	28	349	26	318	28	349	**4449**
2037/38	28	341	29	353	28	341	29	353	29	353	28	341	29	353	28	341	29	353	29	353	26	321	29	353	**4495**
2038/39	28	381	29	394	28	381	29	394	29	394	28	381	29	394	28	381	29	394	29	394	27	359	29	394	**4987**
2039/40	29	348	30	360	29	348	30	360	30	360	29	348	30	360	29	348	30	360	30	360	27	328	30	360	**4588**
2040/41	29	352	30	363	29	352	30	363	30	363	29	352	30	363	29	352	30	363	30	363	27	331	30	363	**4634**
2041/42	29	355	30	367	29	355	30	367	30	367	29	355	30	367	29	355	30	367	30	367	28	334	30	367	**4680**
2042/43	30	358	31	370	30	358	31	370	31	370	30	358	31	370	30	358	31	370	31	370	28	337	31	370	**4726**
2043/44	30	371	31	383	30	371	31	383	31	383	30	371	31	383	30	371	31	383	31	383	28	349	31	383	**4884**
2044/45	37	408	38	422	37	408	38	422	38	422	37	408	38	422	37	408	38	422	38	422	35	384	38	422	**5420**
2045/46	31	369	32	381	31	369	32	381	32	381	31	369	32	381	31	369	32	381	32	381	29	347	32	381	**4865**
2046/47	31	372	32	384	31	372	32	384	32	384	31	372	32	384	31	372	32	384	32	384	30	350	32	384	**4911**
2047/48	32	375	33	388	32	375	33	388	33	388	32	375	33	388	32	375	33	388	33	388	30	354	33	388	**4957**

1

Plan 7 - SCGT/C26
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	215	370	4	181	4	175	4	181	4	181	4	175	4	181	215	370	222	382	222	382	202	348	222	382	**4628**
2022/23	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2023/24	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2024/25	192	353	4	140	4	135	4	140	4	140	4	135	4	140	192	353	199	364	199	364	181	332	199	364	**4145**
2025/26	188	349	41	283	39	274	41	283	41	283	39	274	41	283	39	274	41	283	41	283	37	258	41	283	**4037**
2026/27	49	280	51	289	49	280	51	289	51	289	49	280	51	289	49	280	51	289	51	289	46	264	51	289	**4004**
2027/28	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	64	291	66	301	64	291	66	301	66	301	64	291	66	301	64	291	66	301	66	301	60	274	66	301	**4318**
2037/38	89	310	92	320	89	310	92	320	92	320	89	310	92	320	89	310	92	320	92	320	84	292	92	320	**4860**
2038/39	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2039/40	51	281	52	290	51	281	52	290	52	290	51	281	52	290	51	281	52	290	52	290	48	265	52	290	**4039**
2040/41	78	302	81	312	78	302	81	312	81	312	78	302	81	312	78	302	81	312	81	312	74	284	81	312	**4628**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2043/44	63	290	65	300	63	290	65	300	65	300	63	290	65	300	63	290	65	300	65	300	59	273	65	300	**4295**
2044/45	87	308	90	319	87	308	90	319	90	319	87	308	90	319	87	308	90	319	90	319	82	290	90	319	**4814**
2045/46	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2046/47	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2047/48	76	300	79	310	76	300	79	310	79	310	76	300	79	310	76	300	79	310	79	310	72	283	79	310	**4581**

Plan 8 - CCGT/C26
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	215	370	4	181	4	175	4	181	4	181	4	175	4	181	215	370	222	382	222	382	202	348	222	382	**4628**
2022/23	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2023/24	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2024/25	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2025/26	186	348	39	282	38	273	39	282	39	282	38	273	39	282	38	273	39	282	39	282	36	257	39	282	**4007**
2026/27	49	280	51	289	49	280	51	289	51	289	49	280	51	289	49	280	51	289	51	289	46	264	51	289	**4004**
2027/28	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2037/38	50	281	52	290	50	281	52	290	52	290	50	281	52	290	50	281	52	290	52	290	47	264	52	290	**4028**
2038/39	75	299	77	309	75	299	77	309	77	309	75	299	77	309	75	299	77	309	77	309	71	282	77	309	**4555**
2039/40	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2040/41	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2041/42	64	291	66	301	64	291	66	301	66	301	64	291	66	301	64	291	66	301	66	301	60	274	66	301	**4325**
2042/43	85	307	88	317	85	307	88	317	88	317	85	307	88	317	85	307	88	317	88	317	80	289	88	317	**4767**
2043/44	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2044/45	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2045/46	74	298	76	308	74	298	76	308	76	308	74	298	76	308	74	298	76	308	76	308	69	281	76	308	**4528**
2046/47	98	316	101	327	98	316	101	327	101	327	98	316	101	327	98	316	101	327	101	327	92	298	101	327	**5045**
2047/48	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**

Plan 9 - Wind/C26
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	215	370	4	181	4	175	4	181	4	181	4	175	4	181	215	370	222	382	222	382	202	348	222	382	**4628**
2022/23	213	368	4	178	4	172	4	178	4	178	4	172	4	178	213	368	220	381	220	381	201	347	220	381	**4592**
2023/24	213	368	4	177	4	171	4	177	4	177	4	171	4	177	213	368	220	380	220	380	201	347	220	380	**4586**
2024/25	219	372	4	187	4	181	4	187	4	187	4	181	4	187	219	372	226	385	226	385	206	351	226	385	**4704**
2025/26	214	369	68	303	66	294	68	303	68	303	66	294	68	303	66	294	68	303	68	303	62	277	68	303	**4598**
2026/27	49	280	51	289	49	280	51	289	51	289	49	280	51	289	49	280	51	289	51	289	46	264	51	289	**4004**
2027/28	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	66	292	68	302	66	292	68	302	68	302	66	292	68	302	66	292	68	302	68	302	62	275	68	302	**4355**
2036/37	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2037/38	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2038/39	50	281	52	290	50	281	52	290	52	290	50	281	52	290	50	281	52	290	52	290	47	264	52	290	**4028**
2039/40	76	300	78	310	76	300	78	310	78	310	76	300	78	310	76	300	78	310	78	310	71	282	78	310	**4568**
2040/41	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	64	291	67	301	64	291	67	301	67	301	64	291	67	301	64	291	67	301	67	301	61	274	67	301	**4332**
2043/44	85	307	88	317	85	307	88	317	88	317	85	307	88	317	85	307	88	317	88	317	80	289	88	317	**4767**
2044/45	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2045/46	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2046/47	73	298	76	308	73	298	76	308	76	308	73	298	76	308	73	298	76	308	76	308	69	281	76	308	**4519**
2047/48	98	316	101	327	98	316	101	327	101	327	98	316	101	327	98	316	101	327	101	327	92	298	101	327	**5045**

Plan 10 - K22/C29
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2021/22	218	372	4	186	4	180	4	186	4	186	4	180	4	186	218	372	225	384	225	384	205	350	225	384	**4688**
2022/23	191	351	4	136	4	132	4	136	4	136	4	132	4	136	191	351	197	363	197	363	179	331	197	363	**4107**
2023/24	186	348	4	129	10	130	11	134	11	134	10	130	11	134	196	350	202	362	202	362	184	330	202	362	**4134**
2024/25	196	350	11	134	10	130	11	134	11	134	10	130	11	134	196	350	202	362	202	362	184	330	202	362	**4157**
2025/26	196	350	50	285	48	275	50	285	50	285	48	275	50	285	48	275	50	285	50	285	45	259	50	285	**4159**
2026/27	55	286	57	295	55	286	57	295	57	295	55	286	57	295	55	286	57	295	57	295	52	269	57	295	**4157**
2027/28	55	286	57	295	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4041**
2028/29	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2029/30	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2030/31	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2031/32	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2032/33	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2033/34	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2034/35	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2035/36	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2036/37	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2037/38	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2038/39	54	283	55	293	54	283	55	293	55	293	54	283	55	293	54	283	55	293	55	293	50	267	55	293	**4099**
2039/40	79	302	81	312	79	302	81	312	81	312	79	302	81	312	79	302	81	312	81	312	74	284	81	312	**4637**
2040/41	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2041/42	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2042/43	67	294	70	303	67	294	70	303	70	303	67	294	70	303	67	294	70	303	70	303	63	276	70	303	**4395**
2043/44	92	312	95	323	92	312	95	323	95	323	92	312	95	323	92	312	95	323	95	323	87	294	95	323	**4923**
2044/45	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**
2045/46	54	283	55	293	54	283	55	293	55	293	54	283	55	293	54	283	55	293	55	293	50	267	55	293	**4099**
2046/47	77	301	80	311	77	301	80	311	80	311	77	301	80	311	77	301	80	311	80	311	73	283	80	311	**4605**
2047/48	50	280	51	290	50	280	51	290	51	290	50	280	51	290	50	280	51	290	51	290	47	264	51	290	**4018**

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Plan 11 - K19/C31/250MW
Maximum Import (GWh)

FY	April On-Peak	April Off-Peak	May On-Peak	May Off-Peak	June On-Peak	June Off-Peak	July On-Peak	July Off-Peak	August On-Peak	August Off-Peak	September On-Peak	September Off-Peak	October On-Peak	October Off-Peak	November On-Peak	November Off-Peak	December On-Peak	December Off-Peak	January On-Peak	January Off-Peak	February On-Peak	February Off-Peak	March On-Peak	March Off-Peak	TOTAL
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	169	4	175	4	175	4	169	4	175	186	393	193	406	193	406	176	370	193	406	**4470**
2021/22	186	393	4	175	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4675**
2022/23	196	395	11	180	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4699**
2023/24	215	409	11	214	10	207	11	214	11	214	10	207	11	214	215	409	222	423	222	423	202	385	222	423	**5103**
2024/25	196	395	11	180	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4699**
2025/26	196	395	50	331	48	320	50	331	50	331	48	320	50	331	48	320	50	331	50	331	45	301	50	331	**4701**
2026/27	55	330	57	341	55	330	57	341	57	341	55	330	57	341	55	330	57	341	57	341	52	311	57	341	**4699**
2027/28	59	327	61	338	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4583**
2028/29	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2029/30	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2030/31	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2031/32	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2032/33	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2033/34	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2034/35	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2035/36	50	339	51	351	41	304	42	314	42	314	41	304	42	314	41	304	42	314	42	314	39	286	42	314	**4286**
2036/37	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2037/38	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2038/39	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2039/40	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2040/41	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2041/42	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2042/43	55	299	57	309	55	299	57	309	57	309	55	299	57	309	55	299	57	309	57	309	52	281	57	309	**4306**
2043/44	80	317	82	328	80	317	82	328	82	328	80	317	82	328	80	317	82	328	82	328	75	299	82	328	**4832**
2044/45	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2045/46	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2046/47	69	309	71	320	69	309	71	320	71	320	69	309	71	320	69	309	71	320	71	320	65	291	71	320	**4607**
2047/48	93	327	96	338	93	327	96	338	96	338	93	327	96	338	93	327	96	338	96	338	88	308	96	338	**5122**

Plan 12 - K19/C31/750MW
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	187	348	4	130	45	241	47	249	47	249	45	241	47	249	228	464	236	479	236	479	215	437	236	479	**5618**
2021/22	228	464	47	249	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6054**
2022/23	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2023/24	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2024/25	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2025/26	246	544	72	417	69	404	72	417	72	417	69	404	72	417	69	404	72	417	72	417	65	380	72	417	**6079**
2026/27	72	427	74	442	72	427	74	442	74	442	72	427	74	442	72	427	74	442	74	442	68	402	74	442	**6077**
2027/28	69	405	72	419	63	400	65	413	65	413	63	400	65	413	63	400	65	413	65	413	59	377	65	413	**5661**
2028/29	63	398	65	411	63	398	65	411	65	411	63	398	65	411	63	398	65	411	65	411	59	374	65	411	**5605**
2029/30	63	419	65	433	63	419	65	433	65	433	63	419	65	433	63	419	65	433	65	433	59	394	65	433	**5867**
2030/31	64	459	66	474	64	459	66	474	66	474	64	459	66	474	64	459	66	474	66	474	60	432	66	474	**6358**
2031/32	64	408	66	421	64	408	66	421	66	421	64	408	66	421	64	408	66	421	66	421	60	384	66	421	**5741**
2032/33	64	411	66	424	64	411	66	424	66	424	64	411	66	424	64	411	66	424	66	424	60	387	66	424	**5781**
2033/34	64	414	67	428	64	414	67	428	67	428	64	414	67	428	64	414	67	428	67	428	61	390	67	428	**5825**
2034/35	65	417	67	431	65	417	67	431	67	431	65	417	67	431	65	417	67	431	67	431	61	393	67	431	**5871**
2035/36	64	413	67	427	27	336	28	347	28	347	27	336	28	347	27	336	28	347	28	347	26	316	28	347	**4656**
2036/37	28	338	28	349	28	338	28	349	28	349	28	338	28	349	28	338	28	349	28	349	26	318	28	349	**4449**
2037/38	28	341	29	353	28	341	29	353	29	353	28	341	29	353	28	341	29	353	29	353	26	321	29	353	**4495**
2038/39	28	345	29	356	28	345	29	356	29	356	28	345	29	356	28	345	29	356	29	356	27	325	29	356	**4542**
2039/40	29	352	30	364	29	352	30	364	30	364	29	352	30	364	29	352	30	364	30	364	27	331	30	364	**4633**
2040/41	29	396	30	409	29	396	30	409	30	409	29	396	30	409	29	396	30	409	30	409	27	373	30	409	**5171**
2041/42	29	355	30	367	29	355	30	367	30	367	29	355	30	367	29	355	30	367	30	367	28	334	30	367	**4680**
2042/43	30	358	31	370	30	358	31	370	31	370	30	358	31	370	30	358	31	370	31	370	28	337	31	370	**4726**
2043/44	30	375	31	387	30	375	31	387	31	387	30	375	31	387	30	375	31	387	31	387	28	353	31	387	**4927**
2044/45	35	407	36	420	35	407	36	420	36	420	35	407	36	420	35	407	36	420	36	420	33	383	36	420	**5382**
2045/46	31	369	32	381	31	369	32	381	32	381	31	369	32	381	31	369	32	381	32	381	29	347	32	381	**4865**
2046/47	31	372	32	384	31	372	32	384	32	384	31	372	32	384	31	372	32	384	32	384	30	350	32	384	**4911**
2047/48	32	389	33	402	32	389	33	402	33	402	32	389	33	402	32	389	33	402	33	402	30	366	33	402	**5121**

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Plan 13 - K19/C25/250MW
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	186	348	4	129	4	169	4	175	4	175	4	169	4	175	186	393	193	406	193	406	176	370	193	406	**4470**
2021/22	186	393	4	175	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4675**
2022/23	196	395	11	180	10	174	11	180	11	180	10	174	11	180	196	395	202	408	202	408	184	372	202	408	**4699**
2023/24	218	411	11	220	10	213	11	220	11	220	10	213	11	220	218	411	225	425	225	425	205	387	225	425	**5173**
2024/25	231	428	12	250	12	242	12	250	12	250	12	242	12	250	231	428	239	442	239	442	218	403	239	442	**5539**
2025/26	201	405	44	335	43	324	44	335	44	335	43	324	44	335	43	324	44	335	44	335	40	305	44	335	**4701**
2026/27	55	331	56	342	55	331	56	342	56	342	55	331	56	342	55	331	56	342	56	342	51	312	56	342	**4699**
2027/28	59	327	61	338	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4583**
2028/29	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2029/30	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2030/31	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2031/32	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2032/33	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2033/34	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2034/35	50	325	51	336	50	325	51	336	51	336	50	325	51	336	50	325	51	336	51	336	47	306	51	336	**4560**
2035/36	50	339	51	351	41	304	42	314	42	314	41	304	42	314	41	304	42	314	42	314	39	286	42	314	**4286**
2036/37	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2037/38	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2038/39	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2039/40	70	310	73	321	70	310	73	321	73	321	70	310	73	321	70	310	73	321	73	321	66	292	73	321	**4635**
2040/41	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2041/42	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2042/43	59	302	61	312	59	302	61	312	61	312	59	302	61	312	59	302	61	312	61	312	56	284	61	312	**4394**
2043/44	84	321	87	331	84	321	87	331	87	331	84	321	87	331	84	321	87	331	87	331	79	302	87	331	**4931**
2044/45	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2045/46	51	296	53	306	51	296	53	306	53	306	51	296	53	306	51	296	53	306	53	306	48	279	53	306	**4230**
2046/47	69	309	71	320	69	309	71	320	71	320	69	309	71	320	69	309	71	320	71	320	65	291	71	320	**4607**
2047/48	93	327	96	338	93	327	96	338	96	338	93	327	96	338	93	327	96	338	96	338	88	308	96	338	**5122**

Plan 14 - K19/C25/750MW (WPS Sale & Inv)

Maximum Import (GWh)

		April		May		June		July		August		September		October		November		December		January		February		March		
	FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
	2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
	2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
	2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
	2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
	2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
	2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
	2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
	2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
	2020/21	187	348	4	130	45	241	47	249	47	249	45	241	47	249	228	464	236	479	236	479	215	437	236	479	**5618**
	2021/22	228	464	47	249	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6054**
	2022/23	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
	2023/24	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
	2024/25	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
	2025/26	246	544	72	417	69	404	72	417	72	417	69	404	72	417	69	404	72	417	72	417	65	380	72	417	**6079**
	2026/27	69	399	71	412	95	432	98	446	98	446	95	432	98	446	95	432	98	446	98	446	90	407	98	446	**6297**
	2027/28	92	400	95	413	100	426	103	440	103	440	100	426	103	440	100	426	103	440	103	440	94	401	103	440	**6336**
	2028/29	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2029/30	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2030/31	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2031/32	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2032/33	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2033/34	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2034/35	99	421	103	435	99	421	103	435	103	435	99	421	103	435	99	421	103	435	103	435	94	396	103	435	**6335**
	2035/36	107	486	110	502	70	409	72	423	72	423	70	409	72	423	70	409	72	423	72	423	66	385	72	423	**6060**
	2036/37	72	432	75	447	28	340	29	351	29	351	28	340	29	351	28	340	29	351	29	351	26	320	29	351	**4752**
	2037/38	28	341	29	353	28	341	29	353	29	353	28	341	29	353	28	341	29	353	29	353	26	321	29	353	**4495**
	2038/39	28	345	29	356	28	345	29	356	29	356	28	345	29	356	28	345	29	356	29	356	27	325	29	356	**4542**
	2039/40	29	353	30	364	29	353	30	364	30	364	29	353	30	364	29	353	30	364	30	364	27	332	30	364	**4642**
	2040/41	29	396	30	409	29	396	30	409	30	409	29	396	30	409	29	396	30	409	30	409	27	373	30	409	**5171**
	2041/42	29	355	30	367	29	355	30	367	30	367	29	355	30	367	29	355	30	367	30	367	28	334	30	367	**4680**
	2042/43	30	358	31	370	30	358	31	370	31	370	30	358	31	370	30	358	31	370	31	370	28	337	31	370	**4726**
	2043/44	30	375	31	387	30	375	31	387	31	387	30	375	31	387	30	375	31	387	31	387	28	353	31	387	**4927**
	2044/45	35	407	36	420	35	407	36	420	36	420	35	407	36	420	35	407	36	420	36	420	33	383	36	420	**5382**
	2045/46	31	369	32	381	31	369	32	381	32	381	31	369	32	381	31	369	32	381	32	381	29	347	32	381	**4865**
	2046/47	31	372	32	384	31	372	32	384	32	384	31	372	32	384	31	372	32	384	32	384	30	350	32	384	**4911**
1	2047/48	32	389	33	402	32	389	33	402	33	402	32	389	33	402	32	389	33	402	33	402	30	366	33	402	**5121**

Plan 15 - K19/C25/750MW
Maximum Import (GWh)

	April		May		June		July		August		September		October		November		December		January		February		March		
FY	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	**TOTAL**
2012/13	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2013/14	62	306	20	282	19	273	20	282	20	282	19	273	20	282	62	306	64	316	64	316	59	288	64	316	**4018**
2014/15	61	305	3	242	3	234	3	242	3	242	3	234	3	242	112	325	116	336	116	336	105	306	116	336	**4018**
2015/16	112	325	5	137	5	133	5	137	5	137	5	133	5	137	192	351	198	363	198	363	181	331	198	363	**4019**
2016/17	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2017/18	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2018/19	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2019/20	186	348	4	129	4	125	4	129	4	129	4	125	4	129	186	348	193	360	193	360	176	328	193	360	**4018**
2020/21	187	348	4	130	45	241	47	249	47	249	45	241	47	249	228	464	236	479	236	479	215	437	236	479	**5618**
2021/22	228	464	47	249	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6054**
2022/23	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2023/24	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2024/25	238	466	53	254	52	246	53	254	53	254	52	246	53	254	238	466	246	482	246	482	224	439	246	482	**6077**
2025/26	246	544	72	417	69	404	72	417	72	417	69	404	72	417	69	404	72	417	72	417	65	380	72	417	**6079**
2026/27	72	427	74	442	72	427	74	442	74	442	72	427	74	442	72	427	74	442	74	442	68	402	74	442	**6077**
2027/28	69	405	72	418	63	400	65	413	65	413	63	400	65	413	63	400	65	413	65	413	59	377	65	413	**5657**
2028/29	63	397	65	411	63	397	65	411	65	411	63	397	65	411	63	397	65	411	65	411	59	374	65	411	**5600**
2029/30	63	401	65	414	63	401	65	414	65	414	63	401	65	414	63	401	65	414	65	414	59	377	65	414	**5645**
2030/31	63	404	65	417	63	404	65	417	65	417	63	404	65	417	63	404	65	417	65	417	60	380	65	417	**5690**
2031/32	64	407	66	421	64	407	66	421	66	421	64	407	66	421	64	407	66	421	66	421	60	383	66	421	**5733**
2032/33	64	410	66	424	64	410	66	424	66	424	64	410	66	424	64	410	66	424	66	424	60	387	66	424	**5778**
2033/34	64	414	67	428	64	414	67	428	67	428	64	414	67	428	64	414	67	428	67	428	61	390	67	428	**5825**
2034/35	65	417	67	431	65	417	67	431	67	431	65	417	67	431	65	417	67	431	67	431	61	393	67	431	**5871**
2035/36	64	413	67	427	27	336	28	347	28	347	27	336	28	347	27	336	28	347	28	347	26	316	28	347	**4656**
2036/37	28	338	28	349	28	338	28	349	28	349	28	338	28	349	28	338	28	349	28	349	26	318	28	349	**4449**
2037/38	28	341	29	353	28	341	29	353	29	353	28	341	29	353	28	341	29	353	29	353	26	321	29	353	**4495**
2038/39	28	345	29	356	28	345	29	356	29	356	28	345	29	356	28	345	29	356	29	356	27	325	29	356	**4542**
2039/40	29	352	30	364	29	352	30	364	30	364	29	352	30	364	29	352	30	364	30	364	27	331	30	364	**4633**
2040/41	29	396	30	409	29	396	30	409	30	409	29	396	30	409	29	396	30	409	30	409	27	373	30	409	**5171**
2041/42	29	355	30	367	29	355	30	367	30	367	29	355	30	367	29	355	30	367	30	367	28	334	30	367	**4680**
2042/43	30	358	31	370	30	358	31	370	31	370	30	358	31	370	30	358	31	370	31	370	28	337	31	370	**4726**
2043/44	30	375	31	387	30	375	31	387	31	387	30	375	31	387	30	375	31	387	31	387	28	353	31	387	**4927**
2044/45	35	407	36	420	35	407	36	420	36	420	35	407	36	420	35	407	36	420	36	420	33	383	36	420	**5382**
2045/46	31	369	32	381	31	369	32	381	32	381	31	369	32	381	31	369	32	381	32	381	29	347	32	381	**4865**
2046/47	31	372	32	384	31	372	32	384	32	384	31	372	32	384	31	372	32	384	32	384	30	350	32	384	**4911**
2047/48	32	389	33	402	32	389	33	402	33	402	32	389	33	402	32	389	33	402	33	402	30	366	33	402	**5121**

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

QUESTION:

Are opportunity markets in SPLASH still represented by piecewise linear functions? If so, please provide all workpapers and reports relied upon to define the relationships used in the SPLASH modeling for the NFAT submission.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

QUESTION:

Please provide all benchmarking analysis performed to validate the reasonableness of the price-volume relationships used to model opportunity energy markets in the SPLASH model from the past five years.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

QUESTION:

Please provide a copy of the SPLASH user manual.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak period hydro generation in MWh

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak period hydro generation costs in dollars

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak thermal generation in MWh

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak thermal generation costs in dollars

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak net opportunity sales/purchases in MWh

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Peak and off-peak net opportunity sales/purchase revenues or costs in dollars

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Total imports under import contracts in MWh

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Total import costs from import contracts in dollars

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: For each final SPLASH model run used in the NFAT application economic analysis (both 2012 and 2013 update) please provide the following for each of the 99 water years in each year of the study period:

QUESTION:

Total production costs in dollars

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.2 Description of SPLASH Model; Section: Description of SPLASH Model; Page No.: 1-6

PREAMBLE: Appendix 9.2 provides overview/summary level description of the SPLASH model.

QUESTION:

Please provide all available documentation describing the SPLASH model used in the evaluation of Keeyask and Conawapa for this application, including descriptions of the input data and the algorithms used simulate system operations and costs.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.2; Page No.: 44-45

QUESTION:

Please provide reports, studies or workpapers used by Manitoba Hydro to develop the reference case streamflow assumptions and the modified stream flow cases used as input to the sensitivity analysis - climate change incremental impact on reference case scenario NPV

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.2; Page No.: 47-48

QUESTION:

Please provide reports, studies or workpapers used by Manitoba Hydro to develop the probability assessments on annual average streamflow based on projections from GCM models.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.3; Page No.: 30

QUESTION:

Please provide all workpapers used to generate Figure 5.8 (Historical water supply). Please provide spreadsheet files in Excel-readable format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.1; Page No.: 39; Board Order 5/12

QUESTION:

Please explain why a 5-year drought was chosen to test the impact of a prolonged period of below-average streamflows, rather than a more severe drought event such as that extending from 1929/30 to 1942/3, as proposed in Board Order 5/12?

RESPONSE:

Previous analysis has been completed to study the financial impacts of drought. This analysis studied, among other sensitivities, the following sensitivities to the financial impact of drought:

- Using variable lengths of periods of below-average streamflows
- Using different historical periods of below-average streamflows

One of the general conclusions from the analysis was that lengths of drought beyond five to seven years had relatively insignificant incremental impacts to the financial state of the corporation. Due to the chronological distribution of historical streamflow, a given historical dry period may encompass years approaching or surpassing average streamflow. This leads to the result that beyond the driest five to seven year period, the incremental financial impact is dampened as more years are included.

Another conclusion from the analysis was that the absolute financial impact was modestly greater for the 5 years spanning from 1937/38 to 1941/42 than the period spanning from 1987/88 to 1991/92. However it was noted that for the sake of analyzing the incremental financial impact between two different development plans, the selection between these two 5 year spans didn't significantly affect the results. Since the period spanning from 1987/88 to 1991/92 was judged to better reflect the current regulation patterns and water use practices in watersheds upstream of Manitoba, it was chosen for the drought sensitivity analysis in the NFAT submission.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.2; Page No.: 44

QUESTION:

Please provide the “modified streamflow records” after adjustment based on runoff projections from an ensemble of GCM.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.2; Page No.: 44

QUESTION:

Please provide the unadjusted existing 99 year record of long-term streamflows prior to adjusting for potential changes in average runoff.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: Executive Summary; Page No.: 1

QUESTION:

"Please provide an update on the status of Manitoba Hydro's "efforts to set-up, calibrate and validate hydrological models for each of the river basins to translate [climate models outputs] into projections of river flows." For each river basin, characterize the most current model results. "

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.3; Page No.: 13

QUESTION:

Please provide the WATFLOOD user's manual and any other documentation of the assumptions and operation of the model.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.4; Page No.: 14

QUESTION:

Please provide all workpapers used to generate Figure 14 (Modeled vs. observed streamflows).

Please provide spreadsheet files in Excel-readable format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.4; Page No.: 15

QUESTION:

Please provide the model outputs and all workpapers used to develop the charts in Figure 15 (Future streamflow projections for the Winnipeg River from WATFLOOD). Where possible, please provide spreadsheet files in Excel-readable format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.4; Page No.: 15

QUESTION:

Are the model results depicted in Figure 15 still the most current for the Winnipeg River? If not, please provide WATFLOOD model outputs, streamflow projection charts and workpapers representing the current best streamflow projections for the Winnipeg River basin.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.4; Page No.: 15

QUESTION:

Please provide WATFLOOD model outputs, streamflow projection charts and workpapers representing the current best streamflow projections for the Red River, Assiniboine River, Saskatchewan River, Nelson River and Churchill River basins. If no results are available yet for any particular river basin, please indicate when preliminary results are expected.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.4; Page No.: 15

QUESTION:

The report states at 15: "During this process areas will be identified where specialized model developments could be made to enhance the model's ability to simulate the water balance." Please describe any specialized model developments that have been identified to date, and the reason why they are necessary.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 6.1; Page No.: 28

QUESTION:

The report states at P 28: "Based on current research and studies, Manitoba Hydro has projected ranges associated with future runoff." Please provide all research and studies used as the basis for projected ranges of future runoff.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.3; Page No.: 13-14

QUESTION:

How is Lake Winnipeg regulation modeled in WATFLOOD?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix K Manitoba Hydro Climate Change Report Fiscal Year 2012-2013; Section: 2.3.3; Page No.: 13-14

QUESTION:

Please provide a map showing the river basins of the Nelson-Churchill watershed and the Manitoba Hydro-owned hydro generation stations.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.3; Page No.: 14

QUESTION:

Report states at p 14: "Manitoba Hydro's understanding of the timing and energy price implications of GHG emission pricing within its export region is largely based on the views of various independent electricity export price forecast consultants that contribute to Manitoba Hydro's electricity export price forecast." Please provide Manitoba Hydro's understanding of the timing and energy price implications of GHG emission pricing assumed by the forecast consultants used to produce Manitoba Hydro's export price forecast for the 2012 evaluation and 2013 update.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.3; Page No.: 14

QUESTION:

Report states at p 14: "The Manitoba outlook of carbon adders for thermal based electric generation considers GHG emission pricing from other regions within Canada and the U.S. as well as the perspectives of the electricity export price forecast consultants. Based on these considerations, a plausible range (high, reference, low) of future domestic GHG emission prices are produced." Please provide the emission prices in the high, reference and low range for the 2012 evaluation and 2013 update. Please provide these prices in Excel spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.3; Page No.: 14

QUESTION:

Report states at p 14: “The Manitoba outlook of carbon adders for thermal based electric generation considers GHG emission pricing from other regions within Canada and the U.S. as well as the perspectives of the electricity export price forecast consultants. Based on these considerations, a plausible range (high, reference, low) of future domestic GHG emission prices are produced.” Please specify what exactly is meant by a “plausible range”. (i.e. is the “high” case supposed to represent a 75% case? 99%?)

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.3; Page No.: 14

QUESTION:

Report states at p 14: “The Manitoba outlook of carbon adders for thermal based electric generation considers GHG emission pricing from other regions within Canada and the U.S. as well as the perspectives of the electricity export price forecast consultants. Based on these considerations, a plausible range (high, reference, low) of future domestic GHG emission prices are produced.” Please provide all supporting workpapers, studies, actual pricing, and reference materials used to develop the outlook of Manitoba carbon adders. Where possible please provide materials in excel spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1-2.4; Page No.: 1-59

QUESTION:

The NFAT references five transmission projects: (1) Keeyask Transmission project, (2) Conawapa Transmission project, (3) North – South Upgrade project, (4) Manitoba – Minnesota project, and (5) the Great Northern Transmission project. The uncertainty analysis references three scenarios: (a) 750 MW incremental US interconnection, (b) 250 MW incremental US interconnection, and (c) no incremental US interconnection. Which of the five transmission projects will be built in each of the three scenarios considered?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58-59

QUESTION:

Will Minnesota Power own, and pay all costs for all of, the Great Northern Transmission project? If not please specify the portion to be owned or paid for by others, including Manitoba Hydro.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.6.2; Page No.: 25-28

PREAMBLE: It appears that the Bipole III project is assumed to be built before consideration of the Keeyask and Conawapa generation projects.

QUESTION:

Why is the Bipole III project being built?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.6.2; Page No.: 25-28

PREAMBLE: It appears that the Bipole III project is assumed to be built before consideration of the Keeyask and Conawapa generation projects.

QUESTION:

Would the Bipole III project be built if the Keeyask and Conawapa generation projects were not built?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.6.2; Page No.: 25-28

PREAMBLE: It appears that the Bipole III project is assumed to be built before consideration of the Keeyask and Conawapa generation projects.

QUESTION:

Is the Bipole III project necessary for the Keeyask and Conawapa generation projects to be built and placed in-service? Please explain why or why not.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.6.2; Page No.: 25-28

PREAMBLE: It appears that the Bipole III project is assumed to be built before consideration of the Keeyask and Conawapa generation projects.

QUESTION:

What is the estimated capital cost and annual operating cost of the Bipole III project?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.6.2; Page No.: 25-28

PREAMBLE: It appears that the Bipole III project is assumed to be built before consideration of the Keeyask and Conawapa generation projects.

QUESTION:

Are any of the Bipole III project costs included in the economic analyses included in the NFAT? If so, please indicate where in the economic analysis these costs are included and the magnitude of these costs.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1-2.4; Page No.: 1-59

QUESTION:

Have the (1) Keeyask Transmission project, (2) Conawapa Transmission project, (3) North – South Upgrade project, (4) Manitoba – Minnesota project, and (5) the Great Northern Transmission project been considered and included in the latest MTEP? If not, when will these projects be evaluated in the MTEP process and included in the MTEP?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.3.2; Page No.: 22-24

PREAMBLE: Section 7.2 of the draft MTEP13 report – entitled Manitoba Hydro Wind Synergy Study discusses an East Option and a West option for alternative new interconnections between Manitoba Hydro and the US.

QUESTION:

Figure 7.2-1 shows the East option to be a new 500KV line between Dorsey and Blackberry. Is this East option the same as the Manitoba – Minnesota project in the NFAT? If not, please explain the difference. Table 7.2-1 shows the West option to have a higher benefit / cost ratio than the East option. If East option is the same as the Manitoba – Minnesota project in the NFAT, how will the Manitoba – Minnesota project be approved by MISO if it has a lower benefit / cost ratio?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.3.2; Page No.: 22-24

PREAMBLE: Section 7.2 of the draft MTEP13 report – entitled Manitoba Hydro Wind Synergy Study discusses an East Option and a West option for alternative new interconnections between Manitoba Hydro and the US.

QUESTION:

If the West option is approved by MISO and built in place of the Manitoba – Minnesota project, will Manitoba Hydro be able to proceed with its proposed expansion of hydro generation for export to the US? Please explain why or why not.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

PREAMBLE: Tables 5.7 and 5.8 of the NFAT provide current export limits from and import limits to Manitoba from the US, Ontario, and Saskatchewan.

QUESTION:

Please describe how these limits were set and who set these limits.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

PREAMBLE: Tables 5.7 and 5.8 of the NFAT provide current export limits from and import limits to Manitoba from the US, Ontario, and Saskatchewan.

QUESTION:

Please provide documentation, studies, or analyses that support these limits. Where possible, please provide supporting documentation in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

PREAMBLE: Tables 5.7 and 5.8 of the NFAT provide current export limits from and import limits to Manitoba from the US, Ontario, and Saskatchewan.

QUESTION:

Are these limits used by MISO in planning and operating its system today? If not, please provide the limits used by MISO.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.1; Page No.: 56

PREAMBLE: The Manitoba – Minnesota project is described as a 750 MW 500 KV AC line.

QUESTION:

Is this the normal or emergency MW rating of this line?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.1; Page No.: 56; Chapter 5: The Manitoba Hydro System Interconnections and Export Markets, Section 5.2.2.4, page 16

PREAMBLE: The Manitoba – Minnesota project is described as a 750 MW 500 KV AC line.

QUESTION:

By how much does this project change the existing export and import limits shown in Tables 5.7 and 5.8.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3; Page No.: 7

PREAMBLE: For the potential 250 MW interconnection with the U.S.

QUESTION:

Please describe all transmission additions that are needed to establish the 250 MW interconnection with the US

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3; Page No.: 7

PREAMBLE: For the potential 250 MW interconnection with the U.S.

QUESTION:

Is the 250 MW the rating of additional transmission lines between Manitoba and the US?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3; Page No.: 7; Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

PREAMBLE: For the potential 250 MW interconnection with the U.S.

QUESTION:

By how much does this project / upgrade change the existing export and import limits shown in Tables 5.7 and 5.8.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2; Page No.: 7-10

QUESTION:

Have any portions of the Transmission Asset Condition Assessment Report been completed? If so, please provide copies.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.2.5; Page No.: 51

QUESTION:

Please provide detailed costs estimates for capital costs and annual operating costs for the Conawapa Transmission project. Provide all assumptions, workpapers, and data sources used. Where possible, please provide workpapers and data in electronic spreadsheet format with all formulas intact and readable.

RESPONSE:

A summary of the Conawapa Transmission project cost is included in the following table.

Item	Cost ($2012)
Five 230kV transmission lines with a total length of 10km (includes OPGW communication and licensing)	$3M
Keewatinoow Station upgrades (new circuit breakers, CTs and line terminations)	$7M
Total	$10 million ($2012)

The detailed breakdown would require disclosure of commercially sensitive information and has been provided to the IEC in confidence.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3.5; Page No.: 55

QUESTION:

Please provide detailed costs estimates for capital costs and annual operating costs for the North – South Upgrade project. Provide all assumptions, workpapers, and data sources used. Where possible, please provide workpapers and data in electronic spreadsheet format with all formulas intact and readable.

RESPONSE: A detailed summary of the North-South Upgrade Project cost is included in the following table.

Item	Cost ($2012)
HVdc system upgrades (including splitting northern HVDC collector systems, addition of a new 300 MVar filter at the Radisson Converter Station, addition of a new synchronous condenser, circuit breaker replacements and a 230 kV line Sectionalization, Kettle ring bus connection)	$143M
Four 230kV new transmission lines with a total length of 462km (include license and communications	$139M
Equipment Upgrades at various stations (riser, CTs and SVC) and line retentions	$58M
Total	$340M (in 2012 dollars)

Once all of the lines are in service, the annual O&M is approximately $400,000. A detailed breakdown of annual operating cost would require disclosure of commercially sensitive information which has been provided in confidence to the IEC. Please see the confidential material provided in response to LCA/MH-153.

REFERENCE: Executive Summary; Section: Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities; 2013 Update to Forecasts and DSM Sensitivities; Page No.: 20; 31-33

PREAMBLE: Refer to the NFAT Executive Summary, page 20 of 42 at 8 -15, in which Manitoba Hydro states that its uncertainty analysis involving the testing of multiple variables demonstrated that one of the three variables that had the most significant impact on the economic evaluation of alternative development plans was natural gas price. Subsequently on page 31-33, Manitoba Hydro describes the "2013 Update to Forecasts and DSM Sensitivities":

QUESTION:

Please identify the source for the natural gas price forecast used for the economic evaluation of alternative development plans, including reference, high and low price forecasts and any other price forecasts used by Manitoba Hydro but not included in the NFAT.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Executive Summary; Section: Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities; 2013 Update to Forecasts and DSM Sensitivities; Page No.: 20; 31-33

PREAMBLE: Refer to the NFAT Executive Summary, page 20 of 42 at 8 -15, in which Manitoba Hydro states that its uncertainty analysis involving the testing of multiple variables demonstrated that one of the three variables that had the most significant impact on the economic evaluation of alternative development plans was natural gas price. Subsequently on page 31-33, Manitoba Hydro describes the "2013 Update to Forecasts and DSM Sensitivities":

QUESTION:

Please describe the key differentiating assumptions among the reference, high and low natural gas price forecasts used.

RESPONSE:

In addition to providing a composite, or consensus, reference case forecast of long-term natural gas prices, it is traditional utility practice to provide alternative planning cases that reflect forecast uncertainty. There are three common methods that are typically used to provide these alternative views: (1) deterministic techniques using a consensus of one or more independent forecasters' views of low and high price scenarios; (2) stochastic techniques based on implied "future volatilities" of natural gas options markets; and (3) stochastic techniques based on historical natural gas price volatility (with variations based on the length of the historical period).

For the 2013/2014 year, the natural gas alternative price forecast included in the Energy Price Outlook (EPO) has moved to a deterministic methodology that uses a consensus view of high and low price scenarios provided by the suite of independent forecasters that constitute the forecasts of both the EPO and the Electricity Export Price Forecast. For the 2012/2013 year, and at least a decade of previous EPOs, the natural gas alternative price forecast was derived by calculating the historical annual volatility of real natural gas prices over the period 1972-current year, and applying a rule of +/- 1 standard deviation to the reference case forecast for the derivation of high/low natural gas price forecasts, and +/- ½ standard deviation for the derivation of medium-high/medium-low price forecasts.

For the 2013/2014 year, Manitoba Hydro requested of each of the energy market consultants a Reference, High and Low natural gas price forecast case as follows:

- The "Reference" Case should be the consultant's best estimate of the future;
- The "High" Case should represent a plausible scenario reflecting the upper limit of prolonged pricing;
- The "Low" Case should represent a plausible scenario reflecting the lower limit of prolonged pricing.

REFERENCE: Executive Summary; Section: Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities; 2013 Update to Forecasts and DSM Sensitivities; Page No.: 20; 31-33

PREAMBLE: Refer to the NFAT Executive Summary, page 20 of 42 at 8 -15, in which Manitoba Hydro states that its uncertainty analysis involving the testing of multiple variables demonstrated that one of the three variables that had the most significant impact on the economic evaluation of alternative development plans was natural gas price. Subsequently on page 31-33, Manitoba Hydro describes the "2013 Update to Forecasts and DSM Sensitivities".

QUESTION:

Please identify the source for any updates made to the natural gas price forecasts as part of the "2013 Update to Forecasts and DSM Sensitivities" analysis, and explain the reason why these forecasts were updated.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Executive Summary; Section: Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities; 2013 Update to Forecasts and DSM Sensitivities; Page No.: 20; 31-33

PREAMBLE: Refer to the NFAT Executive Summary, page 20 of 42 at 8 -15, in which Manitoba Hydro states that its uncertainty analysis involving the testing of multiple variables demonstrated that one of the three variables that had the most significant impact on the economic evaluation of alternative development plans was natural gas price. Subsequently on page 31-33, Manitoba Hydro describes the "2013 Update to Forecasts and DSM Sensitivities":

QUESTION:

In the alternative, if no analysis of the impact of updated natural gas price forecasts was performed, please explain why not.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Executive Summary; Section: Economic Uncertainty Analysis, Probabilistic Analysis and Sensitivities; 2013 Update to Forecasts and DSM Sensitivities; Page No.: 20; 31-33

PREAMBLE: Refer to the NFAT Executive Summary, page 20 of 42 at 8 -15, in which Manitoba Hydro states that its uncertainty analysis involving the testing of multiple variables demonstrated that one of the three variables that had the most significant impact on the economic evaluation of alternative development plans was natural gas price. Subsequently on page 31-33, Manitoba Hydro describes the "2013 Update to Forecasts and DSM Sensitivities":

QUESTION:

Does Manitoba Hydro plan to conduct any further analysis based on an update of the natural gas price forecasts, and, if so, what source would it use for the long-term natural gas price forecasts?

RESPONSE:

The above noted reference to the statement in the Executive Summary does not accurately reflect what was stated in the Executive Summary. Manitoba Hydro states in lines 13-17 of page 20 of the Executive Summary that one of the three variables that had the most significant impact on the economic evaluations is **energy market prices** which include the impacts of both natural gas and electricity prices. The probabilistic evaluations in Chapter 10 consider a range of natural gas and electricity export prices in the Energy Prices factor.

Manitoba Hydro does not plan to conduct further analysis based on an update of the natural gas price forecast. As part of its annual planning cycle, Manitoba Hydro prepares an update to its natural gas price forecast. As described in Appendix 9.3, Manitoba Hydro uses a consensus based approach for natural gas price forecasting in order to provide an independent perspective on future natural gas prices. Manitoba Hydro uses up to six industry expert consultants in the development of its consensus forecast of natural gas prices.

The two natural gas price forecasts used in the NFAT submission were the 2012/13 forecast, as an input to the main NFAT evaluations, and the 2013/14 forecast, as an input to the 2013 update evaluations. As provided on page 14 of Appendix 9.3, the change in the range of the 2013/14 forecast of natural gas prices relative to the 2012/13 forecast is from an increase of 5% for the low scenario to a decrease of 5% and 6% for the high and reference scenarios, respectively.

The impact on some of the development plans using the updated 2013 reference scenario assumptions, which includes the 2013/14 forecast of natural gas prices, is documented in Chapter 12 of the NFAT submission.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4; Chapter 5: The Manitoba Hydro System Interconnections and Export Markets, Section 5.4.1, page 37

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Please explain how the Preferred Development Plan, which assumes the construction of additional transmission interconnection import/export capacity between Manitoba and Minnesota and Wisconsin, states within the MISO region, is consistent with the observation on page 4 of 13 of the Overview as well as Table 5.11, "2011 Share of Energy Generated by Fuel Type for Selected ISOs" on page 37 of Chapter 5, which shows that natural gas/oil account for only 5% of energy generated within MISO.

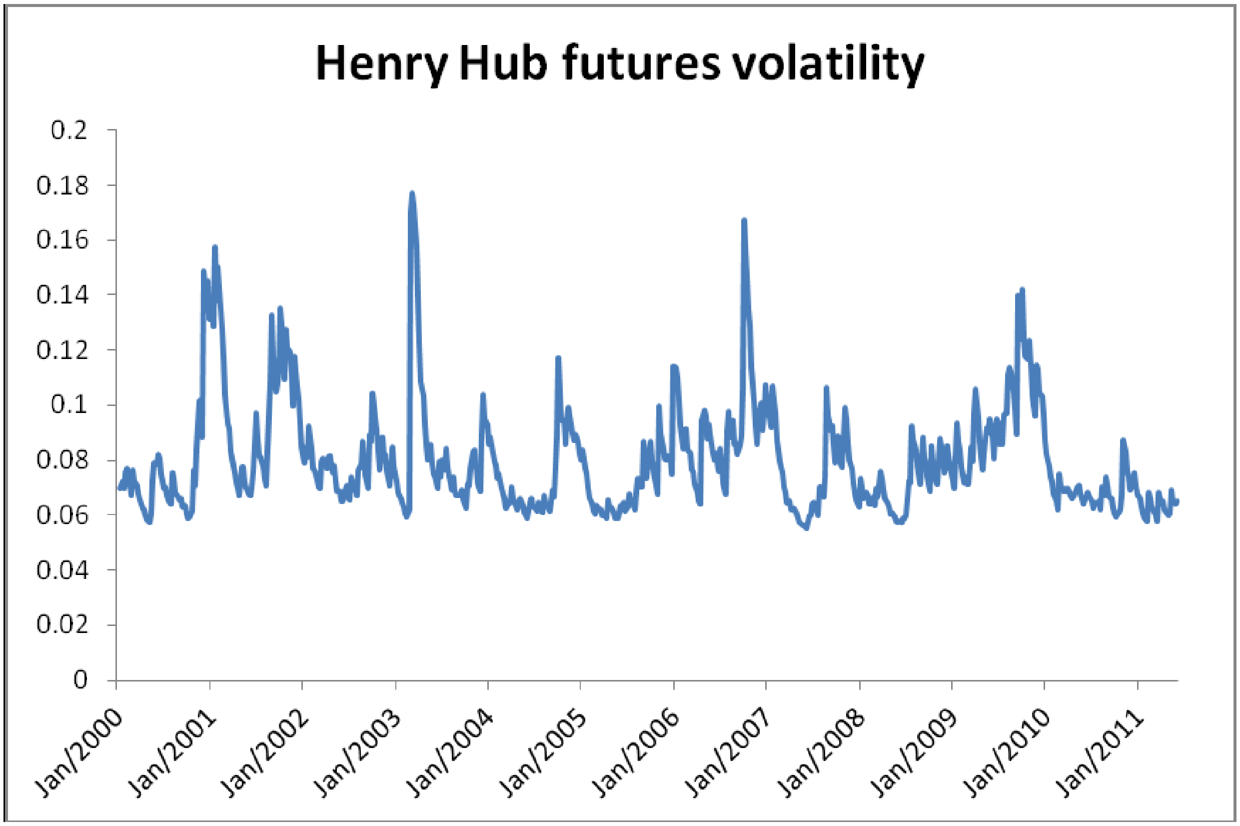
RESPONSE:

Manitoba Hydro notes the following:

- Expected Coal Unit Shutdowns: As stated in Chapter 3 Section 3.5 Aging Generation Fleet, "In its 2013 Annual Energy Outlook, the EIA projects 48 GW of coal-fired capacity will retire by 2020, representing 15% of the total U.S. coal fleet. MISO estimates 6-12 GW of coal capacity will retire by the end of the current decade." Manitoba Hydro notes that these EIA projections capture only the impact of recently implemented US EPA regulations, primarily the Mercury and Air Toxics Standards (MATS), and do not capture potential impacts of EPA's proposed GHG regulations for existing coal fired generation. A draft of proposed GHG regulations affecting the existing coal fleet are not due until June 2014, and no clarity has been provided on what the GHG framework might be.

- Natural Gas Use for Power Generation is Increasing: As stated in Chapter 3, Section 3.4.2 Natural Gas Pricing, "the EIA projects that of the 151 GW of new generation capacity that is expected to be added in the U.S. by 2030, 71% will be natural gas-fired resources." Further "Since 1995, natural gas generation has represented 84% of net capacity additions in the U.S. electricity sector. The historic build-out of gas resources resulted in a significant increase in annual use of natural gas by the electricity sector since the mid-1990s as can be seen in Figure 3.10 [in Chapter 3]. During this period, the percentage of total U.S. natural gas deliveries to the electricity sector has doubled, from 20% in 1997 to 39% by 2012."
- Natural Gas Prices are More Volatile than Coal Prices: As can be seen in the following two graphs, natural gas prices are more volatile than coal prices in the US1.

[1] Source: Extending the G20 Work on Oil price Volatility to Coal and Gas Report by IEA, IEF, IMF and OPEC to G20 Finance Ministers, October 2011.


Henry Hub futures volatility
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
Jan/2000
Jan/2001
Jan/2002
Jan/2003
Jan/2004
Jan/2005
Jan/2006
Jan/2007
Jan/2008
Jan/2009
Jan/2010
Jan/2011


US Coal price volatility
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
Jul/2004
Jul/2005
Jul/2006
Jul/2007
Jul/2008
Jul/2009
Jul/2010

As noted above, there will be less coal fired generation in US and the Midwest in the future. Some of the energy to replace that coal fired generation will come from natural gas fired generation. As natural gas price are more volatile than coal prices, it follows that overall utility fuel price risk will increase as a result.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Please explain how the volatility of natural gas prices is represented in the analysis and over what historic time frame was volatility calculated.

RESPONSE:

The long-term forecast of natural gas prices represents a sustained price trajectory that incorporates price volatility into an equilibrium state. The NFAT probabilistic evaluations considered a range of natural gas price forecasts (high, reference and low) where historical price volatility was considered in the development of the high and low forecasts of natural gas price forecasts.

For the 2012/13 high and low forecasts of natural gas prices used in the probabilistic evaluations, a confidence interval was applied to the consensus reference forecast based on the long-term historical volatility of natural gas prices. The high/low forecast variance band is defined as +/- one standard deviation of the historical natural gas prices over the period from 1972 to date.

Please also see Manitoba Hydro responses to LCA/MH I-164 and CAC/MH I-205.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Please explain whether and how much of the natural gas price volatility is due to availability of natural gas supply at the wellhead and interstate/interprovincial pipeline capacity.

RESPONSE:

As noted in the response to CAC/MH I-205, a study of historical natural gas price volatility completed by the U.S. Energy Information Administration (EIA) in 2007 concluded that annual price volatility at Henry Hub has been high for the past decade, but did not exhibit a consistent increasing or decreasing trend. Examination of post-2006 data reveals that trend volatility has been gradually declining since the time of the study, but results will vary depending on the specific North American natural gas hub chosen.

Manitoba Hydro does not prepare analyses regarding the specific details of the sources of natural gas price volatility. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Did Manitoba Hydro consider any alternative scenarios that included the assumption of new production coming on line in the Western Canadian Sedimentary Basin? If so, please describe how these alternative scenarios differ from the reference high and low cases included in the NFAT and provide all copies of all supporting forecasts and analyses.

RESPONSE:

Manitoba Hydro does not prepare analyses regarding the specific details of new production from the Western Canadian Sedimentary Basin. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Did Manitoba Hydro consider any forecasts or projections of pipeline expansion capacity serving either the province or MISO or both that would allow for greater availability of natural gas supply during the peak period over the forecast horizon? If so what impact did this scenario have on assumed natural gas price volatility and the selection of the Preferred Development Plan? Please identify the source for this information including the names of pipelines assumed to be expanded, the year the expansion is assumed to enter service and the size of the expansion.

RESPONSE:

Manitoba Hydro does not prepare analyses regarding the specific details of pipeline capacity in MISO or North America. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

In what year do the Reference, High and Low natural gas price forecasts relied upon in the NFAT assume that shale gas production in Western Canada will come on line?

RESPONSE:

Manitoba Hydro does not prepare analyses regarding timing of shale gas production in Western Canada. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

Incidentally, the U.S. Energy Information Administration recently released a note indicating that 15% of natural gas production in Canada is already derived from shale gas basins.

http://www.eia.gov/todayinenergy/detail.cfm?id=13491

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

How did the NFAT analysis accommodate the availability of increased oil supply production from the neighboring Bakken Shale region, including delivery capacity by pipeline as well as by rail.

RESPONSE:

Manitoba Hydro does not prepare analyses regarding the specific details of Bakken Shale oil production or its delivery. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

REFERENCE: Overview - Meeting Manitobans' Electricity Needs; Section: U.S. Utilities' Desire to Avoid Coal and Overdependence on Gas; Page No.: 4

PREAMBLE: Refer to NFAT Overview, page 4 of 13 at 16-24, in which Manitoba Hydro states that "U.S. Utilities' desire to Avoid Coal and Overdependence on Gas" and further that "the historic volatility of gas prices and an overdependence on gas-fired base loaded generation create risk."

QUESTION:

Please provide copies of any studies or analyses relied upon for the fuel oil and natural gas forecasts used that assess the amount of technically recoverable and economically recoverable reserves of shale gas and oil in Canada and the U.S. over the forecast horizon.

RESPONSE:

Manitoba Hydro does not prepare analyses regarding the technically and economically recoverable reserves of shale gas and oil in North America. Instead, it relies upon the analysis of the energy market consultants who would complete such analysis as part of their price forecast work.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 46

PREAMBLE: Refer to NFAT Chapter 5 – The Manitoba Hydro System, Interconnections and Export Markets, page 46 of 61 at 20-22, which states "Natural gas was the only other significant marginal fuel, on the margin 23% of the time. As previously noted, due to transmission constraints it is possible for more than one fuel to be on the margin in any particular year."

QUESTION:

Please explain whether the "transmission constraints" referenced above refer to electrical transmission or natural gas pipeline transmission constraints, and if the latter, please provide all forecasts and analyses relied upon for this observation.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.2; Page No.: 13-14

PREAMBLE: Refer to NFAT Appendix 9.3, which describes on pages 13-14 the 2013/2014 forecast of natural gas prices obtained from six independent consultants, of which three forecasts were the same as in the 2012/2013 natural gas price forecasts, and which resulted in adjustments described on page 14 that increased the Low forecast of natural gas prices by 9%.

QUESTION:

Does the adjustment to natural gas prices described above reflect the weighting of all six forecasts or just the three forecasts that were different from the 2012/2013 natural gas price forecasts?

RESPONSE:

In the 2013/14 forecast of natural gas prices, each of the reference, low, and high consensus forecasts reflect equal weighting of the consultants' views. The approximate adjustments to 2012/13 natural gas prices as described on page 14 of Appendix 9.3 are indicative of the resultant consensus forecast for 2013/14 which is based on all six independent consultant forecasts.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.2; Page No.: 13-14

PREAMBLE: Refer to NFAT Appendix 9.3, which describes on pages 13-14 the 2013/2014 forecast of natural gas prices obtained from six independent consultants, of which three forecasts were the same as in the 2012/2013 natural gas price forecasts, and which resulted in adjustments described on page 14 that increased the Low forecast of natural gas prices by 9%.

QUESTION:

Please provide copies of all six 2013/2014 forecasts of natural gas prices and any documentation describing the forecasts provided by the independent consultants.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.2; Page No.: 13-14

PREAMBLE: Refer to NFAT Appendix 9.3, which describes on pages 13-14 the 2013/2014 forecast of natural gas prices obtained from six independent consultants, of which three forecasts were the same as in the 2012/2013 natural gas price forecasts, and which resulted in adjustments described on page 14 that increased the Low forecast of natural gas prices by 9%.

QUESTION:

Please confirm whether the selection of the Preferred Development Plan and the comparative results for all cases shown in the Appendix, Chapter 2, Probabilistic Analysis with Scenarios, including the S-Curves and "Red-Green Quilts", reflect the 2013/2014 updated natural gas price forecasts.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Volume: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.2; Page No.: 13-14

PREAMBLE: Refer to NFAT Appendix 9.3, which describes on pages 13-14 the 2013/2014 forecast of natural gas prices obtained from six independent consultants, of which three forecasts were the same as in the 2012/2013 natural gas price forecasts, and which resulted in adjustments described on page 14 that increased the Low forecast of natural gas prices by 9%.

QUESTION:

Please provide an excel spreadsheet with the 2013/2014 and 2012/2013 natural gas price forecast reference, high, and low cases.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

How much did the 2013 update to the natural gas price forecast change the 2012 forecast of number of customers and use per customer among Manitoba Hydro's Small General Service Commercial, Large General Service Commercial and Residential customer classes?

RESPONSE:

The 2013 update to the natural gas price forecast resulted in no change to the forecast number of customers or the forecast use per customer among Manitoba Hydro's Small General Service Commercial, Large General Service Commercial and Residential customer classes. The natural gas price forecast is not used in the 2013 forecast of number of customers or use per customer.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

Does the forecast assume any increase in the proportion of volumes purchased by Manitoba Hydro's customers through brokers and marketers?

RESPONSE:

The 2012 Natural Gas Volume Forecast projects the proportion of volumes purchased by Manitoba Hydro customers through the Western Transportation Service (brokers) to decline slightly by 2014/15, then holding at approximately at the 2014/15 proportion. For more detail on the annual volumes forecast under the Western Transportation Service please refer to page 33 of the 2012 Natural Gas Volume Forecast filed as Appendix 8.1 of the 2013/14 Centra Gas General Rate Application

(http://www.pub.mb.ca/centra_2013_14_gra/pdf/appendix_8_1_pdf).

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

When were the prices under Manitoba Hydro's Fixed Price Offering for primary gas under one, three and five-year fixed price contracts established and when will they be reset next?

RESPONSE:

Manitoba Hydro's first enrolment period for Fixed Rate Primary Gas Service was offered from February 19, 2009 to March 12, 2009 with a natural gas flow date of May 1, 2009, subsequent enrolments have been offered regularly, generally coinciding with quarterly adjustments to Centra's Primary Gas rates. Prices are set based upon the PUB approved price setting methodology as approved in Order 156/08 and more recently Order 85/13.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

Please provide a percentage distribution of volume purchased under both three and five-year fixed price contracts by customer class by year of commitment, and the value of the contracts for each year.

RESPONSE:

The following three tables present the percentage of the annual volume subscribed by customer class for each fiscal year of an offering. For more detail on the volumes subscribed under the Fixed Rate Primary Gas Service please refer to page 3 of the 2012 Natural Gas Volume Forecast filed as Appendix 8.1 of the 2013/14 Centra Gas General Rate Application (http://www.pub.gov.mb.ca/centra_2013_14_gra/pdf/appendix_8_1.pdf).

The "percentage of volume " is the breakdown between each of the three offerings (1, 3, and 5 year) for each fiscal year. The "Annual Contract Value" is the estimated value per year of each contract that was created in each fiscal year. The total value of the contract for the 3 and 5 year terms would be 3 and 5 times the annual value represented in the table.

Manitoba Hydro’s Fixed Price Offering Small Residential Class						
	1 year contract		3 year contract		5 year contract	
Fiscal Year of Offering	% of volume	Annual Contract Value	% of volume	Annual Contract Value	% of volume	Annual Contract Value
2009/10	48.0%	$86,665	19.0%	$41,497	33.0%	$74,855
2010/11	38.2%	$41,632	33.1%	$37,764	28.7%	$33,172
2011/12	6.5%	$3,170	49.5%	$25,364	43.9%	$23,492
2012/13	28.8%	$4,684	49.5%	$8,917	21.7%	$3,880

Manitoba Hydro’s Fixed Price Offering Small Commercial Class						
	1 year contract		3 year contract		5 year contract	
Fiscal Year of Offering	% of volume	Annual Contract Value	% of volume	Annual Contract Value	% of volume	Annual Contract Value
2009/10	95.4%	$13,583	1.9%	$321	2.7%	$477
2010/11	59.8%	$4,981	9.3%	$851	30.9%	$3,218
2011/12	0.0%	$0	0.0%	$0	100.0%	$2,794
2012/13	0.0%	$0	100.0%	$3,467	0.0%	$0

Manitoba Hydro's Fixed Price Offering Large Commercial Class						
	1 year contract		3 year contract		5 year contract	
Fiscal Year of Offering	% of volume	Annual Contract Value	% of volume	Annual Contract Value	% of volume	Annual Contract Value
2009/10	87.5%	$533,828	8.4%	$55,012	4.2%	$27,415
2010/11	1.0%	$3,887	61.5%	$270,759	37.5%	$174,150
2011/12	0.0%	$0	89.7%	$146,208	10.3%	$17,237
2012/13	5.7%	$9,580	94.3%	$174,573	0.0%	$0

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

Do the three and five year fixed price contracts include escalators?

RESPONSE:

Escalators are not included in the three and five year Manitoba Hydro Fixed Price Offerings. Prices are fixed at the contract rate for the full term of the contract.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Natural Gas Demand & Supply; Page No.: 13

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 5.0, Natural Gas Demand & Supply, page 13:

QUESTION:

Please provide the definition of “primary gas” and a copy of the tariff describing the terms and conditions of this service.

RESPONSE:

“Primary Gas” refers to natural gas supply that is acquired from Western Canadian supply sources and is received by the utility at the Alberta/Saskatchewan border.

Please see the attachment to this response for the Schedule of Sales and Transportation Rates and Services.

CENTRA GAS MANITOBA INC.

Schedule of Sales and Transportation Services and Rates

INDEX

INDEX

I. TERRITORY SERVED

This Schedule of Sales and Transportation Services and Rates applies to the following territory:

District	Zone *	Area Definition
Eastman	1	Ste. Anne, Ste. Anne (R.M.), Blumenort, New Bothwell, Niverville, Steinbach (City), Hanover (R.M.), Otterburne, St. Pierre-Jolys (Village), Grunthal, Desalaberry (R.M.), La Broquerie (R.M.), Ritchot (R.M.), Mitchell, St. Malo, Dufrost, Hadashville, La Broquerie, Ste. Agathe, Marchand, Zhoda, Sarto, Kleefeld, Landmark and St. Adolphe for URD locates only; Altona (Town), St. Joseph, Letellier, Montcalm (R.M.), Dominion City, Franklin (R.M.), Elm Creek, Dufferin (R.M.), Carman (Town), Stanley (R.M.), Morden (Town), Winkler (Town), Plum Coulee (Village), Rhineland (R.M.), Rosenort (U.V.D.), Schanzenfeld, Emerson (Town), Gnadenfeld, Gretna (Village), Morris (Town), Reinfeld, Grey (R.M.), Morris (R.M.), St. Jean Baptiste, Beausejour, Chortitz (Village);
Interlake	1	Portage la Prairie (City), Portage la Prairie (R.M.), MacGregor (Village), St. Claude (Village), North Norfolk (R.M.), Grey (R.M.), Southport (C.F.B.), Oakville, Cartier (R.M.), Elie, Starbuck, Dakota TIPI First Nation, Elm Creek;
Parkland	1	Dauphin (Town), Dauphin (R.M.),
	2	Gladstone (Town), North Norfolk (R.M.), Westbourne (R.M.);
	3	Gilbert Plains, Gilbert Plains (R.M.), Grandview (Town), Grandview (R.M.), St. Lazare (Village), Neepawa (Town), Miniota (R.M.), Miniota,
	4	Roblin (Town), Shell River (R.M.), Inglis, Shellmouth (R.M.), Boulten (R.M.), Russell (Town), Russell (R.M.), Harrowby, Binscarth (Village), Minnedosa (Town), Ellice (R.M.), Archie (R.M.), Shoal Lake (Town), Shoal Lake (R.M.);
Westman	3	Langford (R.M.), North Cypress (R.M.), Virden, Hartney (Town), Cameron (R.M.), Melita (Town), Arthur (R.M.), Glendwood (R.M.), Pipestone (R.M.), Souris (Town), Odanah (R.M.), Brandon (City), Cornwallis (R.M.), Elton (R.M.), Forrest, Carberry, North Cypress (R.M.), Shilo (C.F.B)
	4	Rivers (Town), 00-ZA-WE-KWUN, Odanah (R.M.), Hamiota (R.M), Wallace (R.M.), Boissevain (Town), Morton (R.M.), Killarney (Town), Turtle Mountain (R.M.), Deloraine (Town), Winchester (R.M.), Elkhorn (Village), Hamiota (Village), Minto (R.M.), Kola;
Winnipeg East	1	Winnipeg, Headingley, Ile Des Chênes, LaSalle, Landmark, Lorette, Dugald, Oakbank, Tyndall, Garson, Stonewall, Stony Mountain, Selkirk, Clandeboye, Petersfield, Matlock, Winnipeg Beach (Town), Gimli (R.M.), East St. Paul (R.M.), West St. Paul (R.M.), Lockport, Birds Hill, Oak Bluff, Brokenhead (R.M.), MacDonald (R.M.), Richot (R.M.), Rockwood (R.M.), Rosser (R.M.), Springfield (R.M.), St. Andrews (R.M.), St. Clements (R.M.), Tache (R.M.), Sandy Hook, St. Adolphe, Gimli (Town), Reynolds (L.G.D.), Sanford, Ste. Agathe, Teulon (Town), Dunnottar (Village), Bifrost (R.M.), Arborg (Town), Riverton (Village), Woodlands (R.M.).

Note: See Section IV General Terms and Conditions D) 12) b).

II. DEFINITION OF TERMS

Except where the context expressly states another meaning, the following terms, when used in this Schedule of Sales and Transportation Services and Rates, shall have the following meanings:

A) "10^3m^3" means 1,000 Cubic Meters of gas.

B) "AGENCY AGREEMENT" means an agreement between a Customer and Broker, which at a minimum, authorizes and requires the Broker to act on the Customer's behalf with respect to natural gas service.

C) "AGENCY BILLING AND COLLECTION SERVICE" (or "ABC SERVICE") means a service wherein the Company bills the Customer for gas sold by the Broker to the Customer.

D) "AGENT" means a gas supply Broker acting on behalf of a Customer.

E) "ALBERTA BORDER" means the location(s) in Alberta and Saskatchewan, where natural gas can be accepted into the TransCanada PipeLine system.

F) "ALTERNATE SUPPLY SERVICE" means any supply or source of gas that the Company may offer from time to time, in lieu of curtailment, to Interruptible Sales Service Customers.

G) "ANNUAL QUANTITY DIFFERENCE" means, for purposes of Western Transportation Service, the sum of the monthly Quantity Differences for the twelve months of the Gas Year.

H) "AUTHORIZED SALES VOLUME" means the volume of gas which the Company agrees to sell to the Customer on a given day as specified in a Contract.

I) "BACKSTOP GAS" means that quantity of gas agreed upon by the Company and the Broker and/or Customer which is to supplement, in whole or in part, an impairment to gas deliveries to the Company by or for the Broker and/or Customer.

J) "BASE RATE" means the rate charged for a Service, not including any rate riders or other adjustment factors.

K) "BASIC MONTHLY CHARGE" means a fixed monthly charge that reflects a portion of the costs of being connected to the gas distribution system and is not related to the volume of gas consumed.

L) "BOARD" means the Public Utilities Board of Manitoba.

M) "BROKER" means an entity authorized by the Public Utilities Board of Manitoba to sell natural gas commodity.

N) “BROKER’S PRIMARY GAS PRICE” means the retail price charged by a Broker to a Customer for sales of Primary Gas which is used by the Company to bill the Customer under ABC Service.

O) “BUSINESS DAY” means any calendar day exclusive of Saturdays and Sundays and exclusive of days which are statutory or legal holidays under the laws of Manitoba.

P) “COMPANY” means Centra Gas Manitoba Inc. and its successors and assigns.

Q) “CONTRACT YEAR” means a period of 12 or fewer consecutive months ending on October 31.

R) “CONTRACT” means, for the purposes of these Terms and Conditions of Service and the Rate Schedules into which they are incorporated, an agreement to provide service either implied, written, or oral.

S) “CUBIC METER - DAY” (“m^3/day”) means the maximum volume of gas consumed in a single 24 hour period.

T) “CUBIC METER” (“m^3”) means the volume of gas which occupies one cubic meter when such gas is at a temperature of 15.56 degrees Celsius, and at a pressure of 101.560 kilopascals absolute.

U) “CUSTOMER” (or “Consumer”) shall include any person, firm, or corporation to whom gas is delivered or any other goods or services, including attachment to the system, are provided by the Company. No person, firm or corporation is a Customer in relation to services provided under a “shared services agreement” or services received in the recipient’s capacity as a Broker.

V) “DAY” means a period of 24 consecutive hours beginning and ending at 9:00 a.m., in the time zone in which deliveries are made. The reference date for any day shall be the calendar date on which the 24 hour period shall commence.

W) “DELIVERY POINT” means the location at which the Company shall deliver gas to the Customer.

X) “DELIVERED SERVICE” means natural gas supply purchased by the Company under an arrangement which includes delivery of the natural gas to the Company’s transmission and distribution system.

Y) “DELIVERY SERVICE” means the transmission and distribution of natural gas from the Receipt Point to the designated Delivery Point for the Customer.

Z) “FIRM DAILY CONTRACT DEMAND” means the maximum volume of gas which the Company obligates itself to be ready to deliver and/or sell daily to the Customer’s Delivery Point on a Firm Service basis.

AA) “FIRM SERVICE” means gas service at one Delivery Point and separately metered where the service may not be curtailed except for Force Majeure.

BB) "FUEL GAS" means the quantity of gas which is required to transport gas along the TransCanada PipeLine system, or any other pipeline or storage system that is separate from the Company's transmission and distribution system.

CC) "GAS" means natural gas having a gross heating value of not less than 36 megajoules per Cubic Meter (950 Btu per cubic foot).

DD) "GAS LOAN" means the quantity of gas that must be exchanged between each individual Broker on behalf of that Broker's Customer(s) and the Company for purposes of reconciling differences between Primary Gas Billed and Primary Gas Delivered under Western Transportation Service.

EE) "GAS LOAN MECHANISM" means a mechanism for the exchange of Primary Gas and financial payments between each individual Broker on behalf of that Broker's Customer(s) and the Company under Western Transportation Service.

FF) "GAS YEAR" means a period of 365 consecutive days beginning on the first day of November; provided however, that any such year which contains a date of February 29 shall consist of 366 days.

GG) "GROSS HEATING VALUE" means the total joules expressed in megajoules per Cubic Meter (MJ/m^3) produced by the complete combustion at constant pressure of one (1) Cubic Meter of gas with air, with the gas free of water vapor and the temperature of the gas, air and products of combustion to be at standard temperature and all water formed by combustion reaction to be condensed to the liquid state.

HH) "GROUP" means a group of Customers designated by a Broker in a single agreement under Western Transportation Service or ABC Service.

II) "INTERRUPTIBLE DAILY CONTRACT DEMAND" means the maximum volume of gas which the Company obligates itself to be ready to deliver and/or sell daily to the Customer's Delivery Point on an Interruptible Service basis.

JJ) "INTERRUPTIBLE SERVICE" means gas service at one point of delivery and separately metered where, at any time, the service may be interrupted at the sole discretion of the Company.

KK) "INTERCONNECT POINT" means the point on the TransCanada PipeLine system or any other pipeline designated by such pipelines as their point of receipt.

LL) "JOULE" ("J") is the unit of energy measured as the work done when the point of application of force of one newton is displaced a distance of one meter in the direction of the force. The terms megajoule and gigajoule means 1×10^6 and 1×10^9 joules, respectively.

MM) "LOAN PRICE" means the unit price used in determining the Value of the Gas Loan included under Western Transportation Service.

NN) "MAXIMUM DAILY QUANTITY" means the maximum quantity of gas that the Company will nominate on behalf of a Customer from the Customer's supplier for Primary Gas supply on a given day. The Maximum Daily Quantity does not include Fuel Gas and may be more than the Customer's Firm Daily Contract Demand.

OO) "MEDIUM PRESSURE" means the pressure that the Company utilizes in its distribution system that is no greater than 60 pounds per square inch.

PP) "MONTH" means the period beginning at 9:00 a.m. on the first Day of the calendar month and ending at the same hour on the first Day of the next succeeding calendar month.

QQ) "MONTHLY BILLING DEMAND" means the highest daily consumption measured in Cubic Meters on any given day of the month, provided the month is a Winter Month, or in any Winter Month of the preceding eleven months. For Customers without twelve months of demand billing data, the Monthly Billing Demand may be estimated or otherwise specified by the Company.

RR) "MONTHLY DEMAND CHARGE" means a monthly charge that reflects the Customer's use of the capacity of the system. The Monthly Demand Charge is calculated as the Monthly Billing Demand for the month multiplied by the applicable unit demand rate.

SS) "NOMINATED VOLUME" means the quantity of gas expressed in gigajoules which the Customer has arranged to deliver to the Receipt Point, and the Company has agreed to receive, in a given day.

TT) "NORMAL YEAR GAS REQUIREMENTS" means the annual gas requirements that would be required under weather conditions determined from a 25-year rolling average as calculated from time to time by the Company.

UU) "PREMISES" means the location specified in an application for service, or such other location to which the Company delivers gas.

VV) "PRIMARY GAS" means the gas requirements that may be served with gas from Western Canada which is received at the Alberta Border.

WW) "PRIMARY GAS BILLED" means the quantity of Primary Gas calculated to have been consumed, as rendered by the Company on bills to Customers, in accordance with the Company's practices.

XX) "PRIMARY GAS DELIVERED" means the quantity of Primary Gas delivered by the Broker to the Company as part of the Western Transportation Service Agreement.

YY) "QUANTITY DIFFERENCE" means the difference between the Primary Gas Delivered and the Primary Gas Billed under Western Transportation Service expressed in either Cubic Metres or Gigajoules.

ZZ) "RECEIPT POINT" means the interconnection between the Company's transmission and distribution system and TransCanada PipeLines transmission system.

AAA) "SALES SERVICE" means gas service in which the Company procures gas quantities to satisfy the Customer's gas requirements.

BBB) "SERVICE LINE" means that portion of the Company's distribution system used for the delivery of gas from the main to the inlet side of the meter assigned to the Customer.

CCC) "STANDARD PRESSURE" means an absolute pressure equal to 101.560 kPa at 15.56 degrees Celsius.

DDD) "SUPPLEMENTAL" means the quantity of gas, exclusive of Alternate Supply provided to Interruptible Customers, that is provided by the Company in order to meet gas requirements in excess of the portion of requirements that can be met by Primary Gas.

EEE) "TRANSCANADA" means TransCanada PipeLines Limited.

FFF) "TRANSPORTATION SERVICE (T-SERVICE)" means transmission and/or distribution of Customer-owned gas on the Company's system as defined in the Contract between Customer and the Company.

GGG) "UNAUTHORIZED OVER-RUN GAS" means:
a) any and all quantities of natural gas consumed by an Interruptible Class Customer during a period of time that the Company has curtailed service to that customer, and during which that Customer is not receiving Alternate Supply Service, and/or;
b) any and all quantities of natural gas consumed by a Customer of a Broker that has failed to supply their requirements, during a period of time that the Company has curtailed service to that Customer because the Company is unable to acquire Backstop Gas.

HHH) "UNAUTHORIZED OVER-RUN GAS CHARGE" means a volumetric charge per cubic metre for the procurement and supply of Unauthorized Over-run Gas consumed by a Customer.

III) "UNAUTHORIZED OVER-RUN GAS DELIVERY CHARGE" means a delivery charge per cubic metre for Unauthorized Over-run Gas consumed by a Customer.

JJJ) "VALUE OF THE GAS LOAN" means the amount of money equal to the quantity of the Gas Loan multiplied by the Loan Price as part of Western Transportation Service.

KKK) "VOLUMETRIC CHARGE" means a charge based on the volume of natural gas measured over an extended period of time, such as a monthly billing period.

LLL) "WINTER MONTH" means the months of November, December, January, February, and March.

MMM) "YEAR" means a period of 365 consecutive days; provided however, that any such year which contains a date of February 29 shall consist of 366 days.

III. DESCRIPTION OF AVAILABLE RATES AND SERVICES

This section provides general descriptions of the rates and services offered by the Company and other related matters. The descriptions provided in this section are not comprehensive and may be changed by the Company at any time. The characteristics and charges associated with any of the following services may be changed at any time subject to Board Approval.

The Company offers two basic services. These are Sales Service, where the Company provides some of the Customer's gas requirements, and Transportation Service, where the Company does not provide any of the Customer's gas requirements.

Sales Service is a service in which the Company procures and manages gas supplies, and arranges the delivery of those supplies to the Customer. Sales Service consists of four distinct components: Primary Gas; Supplemental Gas; Transportation to Centra; and Distribution to Customer. **Primary Gas** is natural gas procured at the Alberta Border. Sales Customers may choose to purchase Primary Gas from either the Company or an alternative supplier. **Supplemental Gas** is natural gas procured from all other sources. The Company provides Supplemental Gas to all Sales Customers, regardless of the source of the Customer's Primary Gas. **Transportation to Centra; and Distribution to Customer** includes the management of all gas, including transportation to Manitoba, and the transmission and delivery of that gas to Customers. **Transportation Service** ("T-Service") allows a Customer to procure and deliver its own natural gas supplies to the Company's Receipt Point. The Company's T-Service is the agreement under which the Company delivers that natural gas from the Receipt Point to the Customer's facility. Special Terms and Conditions of Transportation Service are covered in Section V.

Sections IX and X set out the specific rates for both Sales Service and T-Service.

A) OPTIONAL SERVICE OFFERINGS:

1) Western Transportation Service

The Company manages and delivers Broker-provided Primary Gas from the Alberta Border to the Customer's facility. The Company then delivers this gas to the Customer or otherwise as appropriate. An Agency Agreement between the Customer and the Broker, and a separate Western Transportation Service Agreement between the Customer, the Broker and the Company are required to take this service, which may be executed on behalf of the Customer by the Broker as the Customer's agent. Western Transportation Service is subject to the Special Terms and Conditions as set forth in Section VII hereof. Western Transportation Service Customers are eligible for Alternate Supply Service and Backstopping Service as described in the Optional Service Offerings provided herein.

Agency Billing and Collection ("ABC") Service is offered in conjunction with Western Transportation Service. ABC Service allows the Company to bill the Customer for Primary Gas on behalf of the Broker, using the Broker's Primary Gas Price. The Customer makes a single payment to the Company.

2) Alternate Supply Service

The Company may provide, on a best efforts basis, Alternate Supply Service on an interruptible basis to Interruptible Customers requesting such service, who otherwise would be interrupted by the Company for supply reasons. Alternate Supply Service may be arranged by the Company at prices in accordance with the provisions of Section VI hereof.

3) Backstopping Service

The Company may provide Backstopping Service, if requested, on a best efforts basis to T- Service and Western Transportation Service Customers whose gas supply fails or cannot be delivered to the Company's distribution system.

4) Short Term Interruptible Transportation Service

During periods where curtailment would otherwise be implemented, the Customer may elect to provide its own gas supply delivered to the Company's Receipt Point in lieu of Company provided gas supply. The Customer's gas supply will be transported to the Delivery Point under the Short Term Interruptible Transportation Service.

B) SERVICE OFFERINGS BY SERVICE CLASSIFICATION:

Customers are classified as either Small General Class, Large General Class, High Volume Firm Class, Co-op Class, Interruptible Class, Mainline Class, Special Contract Class or Power Station Class.

1) Small General Class ("SGC")

While meter size does not determine which class a Customer is in, SGC Customers, as general guide, receive gas through one meter of the type and capacity typically installed for individual residences. Sales Service and the Optional Service offerings associated therewith are the only services available to these Customers. T- Service is not available. Service is on a firm basis and the charges include a Basic Monthly Charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge; and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. All Customers with annual consumption of less than 680,000 m^3 are eligible for this rate.

Customers that are eligible for this class may elect to be reclassified as Large General Class instead, however, that election will remain in effect until a subsequent election is made and each election must remain effective for a minimum of one year.

Customers in this class are eligible for Western Transportation Service as described in the Optional Service Offerings as provided herein.

2) Large General Class ("LGC")

While meter size does not determine which class a Customer is in, LGC Customers, as a general guide, receive gas through one meter of the type and capacity not commonly installed for individual residences. These Customers receive Firm Sales Service; T-Service is not available. The charges include a Basic Monthly Charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge; and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. All Customers with annual consumption of less than 680,000 m^3 are eligible for this class. Customers who are eligible for this class may elect to be reclassified as SGC. That election, however, will remain in effect until a subsequent election is made and each election must remain effective for a minimum of one year.

Sales Customers in this class are eligible for Western Transportation Service as described in the Optional Service Offerings provided herein.

3) High Volume Firm ("HVF") Class

HVF Customers receive gas on a firm basis through one meter, where annual consumption equals or exceeds 680,000 m^3. These Customers may elect to receive either Firm Sales Service or Firm Transportation Service. The charges include a Basic Monthly Charge, a Monthly Demand Charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge, and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. Customers desiring this service must execute a binding agreement with the Company with a minimum term of one year. Any change in classification from HVF Class to Interruptible Class shall be at the consent of the Company.

Sales Customers in this class are eligible for Western Transportation Service as described in the Optional Service Offerings provided herein. Transportation Service Customers in this class are eligible for Backstopping Service as described in the Optional Service Offerings provided herein.

4) Co-op ("Co-op") Class

Co-op Customers receive gas through one meter where the Customer is served directly from the Company's medium pressure transmission system or through dedicated distribution facilities at pressures in excess of medium pressure and whose annual gas requirements are less than 680,000 m^3. Co-op customers must distribute gas and be regulated by the PUB. Co-op Customers must contract with the Company for 12 months or longer for firm year-round service, and have a load factor of less than 40%.

Co-op Customers may elect Firm Sales Service, or Firm Transportation Service. The charges include a Basic Monthly charge, a Monthly Demand charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge, and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. This service may be subject to Special Terms and Conditions as specified in sections V and VI.

Sales Customers in this class are eligible for Western Transportation Service as described in the Optional Service Offerings provided herein. T-Service Customers in this class are eligible for Backstopping Service as described in the Optional Services Offerings provided herein.

5) Interruptible Class ("IC")

Interruptible Customers receive gas through one meter where the service may be interrupted by the Company from time to time upon notice to the Customer. Interruptible Service is available only in situations where, in the sole opinion of the Company, a benefit exists for the Company or other Customers. Interruptible Service is available to Customers whose annual gas requirements equal or exceed 680,000 m^3 and who contract for such service for a minimum of one year, or to Customers that have received Interruptible Service continuously since December 31, 1996. Sales Service or Transportation Service are available. The charges include a Basic Monthly Charge, a Monthly Demand Charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge, and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. Interruptible Service is subject to Special Terms and Conditions of Service as set out in Sections V and VI, which also includes charges for failure to comply with the Terms and Conditions of the service.

Sales Customers in this class are eligible for Short Term Interruptible Transportation Service, Western Transportation Service, and/or Alternate Supply Service as described in the Optional Service Offerings provided herein. T-Service Customers in this class are eligible for Backstopping Service as described in the Optional Service Offerings provided herein.

6) Mainline Class ("MLC")

Mainline Customers receive gas through one meter where the Customer is served directly from the Company's transmission system or through dedicated distribution facilities at pressures in excess of medium pressure and whose annual gas requirements equal or exceed 680,000 m^3 and who contract for such service for a minimum of one year. Mainline Customers may elect Firm Sales Service, Interruptible Sales Service (in conjunction with Firm Delivery Service), or Firm Transportation Service. The charges include a Basic Monthly Charge, a Monthly Demand Charge, a Primary Gas charge, a Supplemental Gas charge, a Transportation to Centra charge, and a Distribution to Customer Volumetric Charge as described in Sections IX and X of this Schedule of Sales and Transportation Services and Rates. This service may be subject to Special Terms and Conditions as specified in sections V and VI.

Sales Customers in this class are eligible for Alternate Supply Service, Short Term Interruptible Transportation Service and/or Western Transportation Service as described in the Optional Service Offerings provided herein. T-Service Customers in this class are eligible for Backstopping Service as described in the Optional Service Offerings provided herein.

7) Special Contract Class

The Company provides Special Contract service through a written agreement between the Company and a Customer which governs the gas service to the Customer. Special Contract Service may include Sales Service and/or a Transportation Service. This service will be governed by the terms of the individual contract.

8) Power Station Class

The Company provides service to electrical generating stations which use natural gas in the production of electricity through a written agreement between the Company and the Customer which governs the gas service to the Customer. Power Station Service may include Sales Service and/or Transportation Service. This service will be governed by the terms of the individual contract.

IV. GENERAL TERMS AND CONDITIONS

This Section IV deals with sales, delivery, and transportation services provided by the Company.

A) CONTRACT FOR SERVICE

1) General

a) These General Terms and Conditions shall apply to all contracts (howsoever created) for gas service under any of the Company's rate schedules or service classifications, including Special Contracts; provided that, if the provisions of any explicit Contract conflict with these Terms and Conditions, the provisions contained in the explicit Contract shall prevail.

b) These General Terms and Conditions may, subject to approval by the Board, be added to, altered, or amended by the Company from time to time and any such addition, alteration, or amendment shall become effective upon Order of the Board.

2) Application for Service

a) Application for a service line shall be made on a form provided by the Company. The application, when signed by the Customer and accepted by the Company, shall become a contract for gas service.

b) Verbal application for gas service to premises having existing facilities may be accepted by the Company. In such cases, a contract is deemed to be made between the Company and the Customer.

c) When two or more rates and/or services are available to a Customer, the Customer may elect the rates and/or services to be provided to the Customer. In the event that an election is not specified, the Company will make an election. The Customer may make an alternative election at any time subject to reasonable notice. The Customer, having made an election, must remain with that rate and/or service for a period of not less than twelve months following the effective date of the election. All elections are prospective only.

3) Termination

The Customer may terminate the contract by providing no less than seven (7) days notice to the Company, to be effective on the later of seven (7) days following receipt of such notice by the Company or the date specified in such notice by the Customer. Notwithstanding any such termination, the Company retains its rights of access as noted in Paragraph IV B) 8) to its equipment on or in the Customer's property and the Customer remains liable to the Company for any amounts payable under the contract of service up to the latter of the date of termination, or the remaining period of the contract. Any additional contracts or agreements in place between the Customer and the Company remain subject to the termination provisions contained therein.

4) Easements and Rights-of-Way

a) If, before the point of entry at the Premises, a service line must cross property owned by some person other than the Customer, the Company shall obtain from such person a written consent or easement for the installation and maintenance of the service line and related facilities.

b) If the Customer is not the registered owner of the Premises, the Customer shall obtain for the Company from the said owner the necessary consent or easement in writing for the installation and maintenance in said Premises of all necessary facilities for supplying gas; provided that the Company may, at its option, itself acquire such consent or easement.

5) Assignment

All contracts for service shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns, but shall not be assigned or be assignable by the Customer without the consent in writing of the Company first being obtained which consent may be withheld by the Company.

6) Representation

No agent, representative, or employee of the Company has the authority to make any promise, agreement, or representation not incorporated within the Company's Schedule of Sales and Transportation Services and Rates or executed through a contract for service, and any such promise, agreement, or representation shall not bind the Company.

7) Resale of Gas

Gas taken by a Customer at a delivery point shall not be resold, except as permitted by Law.

8) Rates and Charges

In connection with a contract for service, the Customer shall pay the Company at the rates approved from time to time by the Board or other regulatory body having jurisdiction, and shall pay any other charges validly in effect from time to time.

9) The Public Utilities Board Act to Prevail

The provisions of these Terms and Conditions of Service are subject at all times to all applicable Federal, Provincial, and Municipal Legislation including The Public Utilities Board Act (Manitoba) as amended from time to time, or such other legislation as may be enacted in replacement thereof and any lawful Orders of the Board. In the event of any conflict between the provisions of these Terms and Conditions, the provisions of the aforesaid Legislation, or any lawful Order of the Board, the provisions of the said Legislation or Order shall prevail.

B) SERVICE CONNECTION AND CHARGES

1) Authority for Work

No changes, extensions, replacements, repairs, connections, or disconnections to, of, or from the Company's system shall be made except by the Company's duly authorized employees, agents, or contractors.

2) Installation Policy

Subject to IV B) 3) hereof, where the Company's main is adjacent to the Customer Premises, the Company will install, at no additional charge to the Customer, a service line from the main to a meter location selected by the Company, except that where the distance from the property-line crossed by the service line to the entry-point or meter exceeds forty-six meters (150 feet), the Company may invoke and the Customer shall pay an excess distance charge. The Company reserves the right to conduct a feasibility study on each applicant or project and charge an applicable contribution in aid of construction for that Customer and/or any and all Customers in a project, which contribution shall be paid (or suitable arrangements made in lieu thereof to the satisfaction of the Company) prior to commencement of construction.

3) Right of Refusal to Install

The Company may refuse to install a service line if, in the Company's opinion, such installation is not reasonable and practical and would not furnish sufficient business to justify the construction and maintenance thereof, and neither acceptance of an application from nor any cash deposit from the Customer shall be construed as a commitment by the Company to install any service line.

4) Location of Service and Meter

The Company will designate the location of the service lines, meters, and regulators, and will determine the amount of space that must be left unobstructed for the installation and maintenance of such equipment.

5) Service Relocation and Alteration

Where the Customer requests, or where the Customer's conduct requires, that the meter, regulator and/or service line either enter the Premises at a point or follow a route different from that chosen by the Company or alters the existing configuration, it must conform to existing codes and regulations. The Company may charge and the Customer shall pay for all extra costs incurred for the installation or alteration in accordance with the Customer's request, or as made necessary by the Customer's conduct, provided that nothing herein obligates the Company to make the requested or required changes.

6) Meters Installed Within Premises

If the Company has designated an inside meter location, the meter will be installed as close to the service entry point as allowed by existing codes and regulations. Where the Customer desires a meter location other than that chosen by the Company, it must conform to existing codes and regulations, and the Customer will be charged the cost of installing all piping in excess of the amount required by the Company's choice of location. All piping, and other equipment if any, between the main and the meter remains the property of the Company.

7) Additional Meters Installed Within Premises

Additional meters may be installed on request at the Customer's expense. The Company reserves the right to refuse installation of additional meters where such installation is not reasonably necessary for the Customer's purposes.

8) Access to Property

The Customer grants the Company full power, right, and liberty to enter the lands upon which the Premises are situated to break the surface and make necessary excavations for the purpose of locating, installing, repairing, replacing, maintaining, and inspecting all facilities on the said lands. The Company shall do as little damage and cause as little inconvenience as is reasonably possible in doing such work, and shall restore the property as nearly as is reasonably practical, to its former state provided at all times that the Company shall not be obligated to remove its pipelines or other equipment.

9) Commencement of Use of Gas

The Customer agrees to commence using gas on the Premises within six (6) months of the date of installation of the facilities. Failing to so commence, after the sixth month the Customer shall pay the Company's approved Basic Monthly Charge, or at the Company's option, shall pay the full cost of the installation and removal of services.

10) Timing of Installation

The Company reserves the right to determine the timing of the installation of service when by reason of weather, conditions of excavation, and/or other circumstances beyond its control, it is deemed inadvisable to install facilities.

11) Gratuities

Employees of the Company are expressly forbidden to solicit or accept any gratuities from the Customer.

C) CONSUMER CONTRIBUTIONS IN AID OF CONSTRUCTION

1) Refundable Contributions

Where the Company deems anticipated revenue from the Customer insufficient to justify an extension of its distribution system, it may require the Customer to pay a contribution in aid of construction of the extension. The contribution will be refunded after the end of the fifth year under the following circumstances:

a) Full Refund: if, in the sole opinion of the Company, sufficient new Customers or loads are attached to the extension to make it economically feasible, a full refund of the original contribution will be made.

b) Partial Refund: if, in the sole opinion of the Company, new Customers or loads are attached to the extension, but total anticipated revenue from the extension is insufficient to prevent it from being a burden to the Company's other existing Customers, the additional loads will be considered in re-evaluating the original contribution and such re-evaluation may enable a refund to the original Customer to a maximum of the original contribution. Any portion of the refundable contribution not refunded at the end of five (5) years will become a non-refundable contribution.

c) Any refund that may be due to the Customer will first be applied to any outstanding amounts due to the Company by the Customer. Any remaining balance will be refunded to the Customer.

2) Non-Refundable Contributions

Where the Company deems that projected revenue from all potential added connections will be inadequate to prevent an undue burden on existing Customers, it may require the Customer to pay a non-refundable contribution in aid of construction of the extension.

D) MEASUREMENT BILLING AND PAYMENT

1) Meters and Regulators

The Company shall install on the Customer's Premises, at a point to be selected by the Company, such meter(s), regulator(s), and/or other equipment as the Company deems necessary, which shall be and remain the property of the Company.

2) Testing Measurement Equipment

a) In the event that the Customer requests under the Electricity and Gas Inspection Act for the testing of the measurement equipment, and by such testing it is found that the measurement equipment is recording within the allowable tolerances as specified in the Regulations under the said Act, all previous readings shall be deemed to be correct and the Customer shall pay to the Company its charge for testing and changing the equipment. If the measurement equipment is found to be recording outside of allowable tolerances, the cost of testing and changing the meter will be borne by the Company and a correction in billing shall be made as set out in IV D) 4) hereof.

b) The accuracy of measuring equipment shall be verified by the Company at reasonable intervals, but shall not be required more frequently than once in any thirty-day period. In the event either party shall notify the other that it desires a special test of any measuring equipment the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test shall be borne by the requesting party if the equipment tested is found to be in error by not more than 2%.

c) If, upon test, any measuring equipment is found to be in error by not more than 2%, then previous recordings of such equipment shall be considered accurate in computing deliveries of gas. However, the equipment shall be adjusted at once to read as accurately as possible.

d) If, for the period since the last preceding test, it is determined that any measuring equipment is found to be inaccurate by an amount exceeding 2% for such period, then the previous readings of measurement equipment shall be corrected for any period during which the measuring equipment was known to be inaccurate. In such situations, corrections for billing purposes shall be in accordance with section IV D) 4).

3) Meter Reading

Meters shall be read with such frequency as the Company may decide. The Company shall have the right at any time to estimate Customer consumption and to render a bill based upon such estimated consumption. Should the number of consecutive estimated readings exceed five (5), the Company shall, subject to its ability to gain access to the Customer's Premises, read the meter. Notwithstanding the foregoing, the Company may, at its option, require the Customer to read the meter and report such reading in the manner specified by the Company.

4) Failure of Measurement Equipment to Register Properly

If the measurement equipment ceases to register properly, the quantity of gas used will be determined by the most appropriate method, as determined in the sole opinion of the Company. Such methods may include but not be limited to:

a) mathematical calculations and comparisons including prevailing ratio with a parallel meter,

b) the use of the Customer's check measuring equipment, and

c) the amount consumed during the corresponding period of the previous month(s) or year(s), giving due consideration to the weather, processing, and connected load, or

d) if no such information exists, the Company's best estimate, having regard to the circumstances.

A correction in billing shall be made for the period that the measurement equipment failed to register properly, not exceeding two (2) years retroactive from the date of discovery.

5) Billing

a) **General**: Bills will be rendered monthly or by such other period as the Company may determine and the Customer shall pay rendered accounts by the due date specified on the bill. The Company shall assess, and the Customer shall pay, a late payment charge as specified in the rate schedule on all accounts remaining unpaid after the due date. The Company's records of the date of mailing or delivery of bills shall be conclusive evidence of the date of rendering. For purposes of computing monthly bills, "month" shall mean a billing period of approximately thirty (30) days. Bills computed for periods longer or shorter than one month in this context shall be prorated, including fixed charges such as the Basic Monthly Charge and the Monthly Demand Charge where applicable.

Where bills have been rendered, and it is subsequently determined that they have been incorrectly calculated for reasons other than Failure of Measurement Equipment to Register Properly, they shall be recalculated and submitted for payment by the Customer or Refund by the Company. In such situations the recalculations may be retroactive for a maximum period of six years. No penalty or interest shall be included on such rebilled amounts during the retroactive period. Interest charges and/or late payment charges may begin after the due date as specified on the bill when rendered for the corrected amounts.

b) **Application of Payments/Credits to Electricity and Gas Accounts and Other Indebtedness**: Where a Customer pays less than the full balance due on an account which is comprised of charges for the supply of natural gas and electricity including related late payment charges and/or an amount for items other than gas or electricity services and related late payment charges (the "Other Indebtedness"), or receives a credit on the account, in the absence of a specific direction from the Customer, such payment/credit shall be applied in the following order:

i. first to the oldest arrears. Where arrears are of equal vintage, payments shall be applied pro rata to natural gas charges, including related late payment charges, electricity charges, including related late payment charges and to the Other Indebtedness, including related late payment charges;

ii. where there are payments/credits in excess of the amount required to pay the oldest arrears, payments/credits shall be next applied to the next oldest arrears (pro rata in accordance with subparagraph (i) if there is more than one service with arrears of equal vintage), and so on until all arrears are paid;

iii. if there are no other arrears, to current charges, pro rata.

6) Authorization to Disconnect Other Service and/or Install Load Limiting Devices

Where the Customer has an account comprised of charges for electricity and natural gas service, or is the recipient of both electricity and natural gas service at the same address but billed separately, the Customer authorizes the Company to request that Manitoba Hydro disconnect the electric service or alternately install a load limiting device on the electric service where the charges for natural gas service are in arrears and full payment or payment arrangements suitable to the Company have not been made. The installation and removal of the load limiting device and/or disconnection and reconnection of service shall be undertaken in accordance with the procedures as defined in the Gas and Combined Gas/Electric Services Disconnection and Reconnection Policy and Procedure as approved from time to time upon Order of the Board.

7) Guarantee Deposit

Applicants for service may, at the option of the Company, be required to provide a guarantee of payment in the form of a deposit, letter of credit, or other guarantee suitable to the Company. The amount of such guarantee shall not normally exceed the total of estimated billings to the Customer for the three (3) month period of maximum consumption. Guarantee amounts may be assessed at the discretion of the Company. The guarantee is security against any outstanding indebtedness of the Customer, and may, at the Company's discretion, be held by the Company until the Customer discontinues the use of gas at the Premises and the contract is terminated, or the guarantee or part thereof may be applied from time to time against the outstanding indebtedness of the Customer and any amount so applied shall forthwith be paid to the Company by the Customer to replenish such guarantee. The amount of such guarantee is not transferable or assignable.

If the guarantee is provided by way of a deposit, the Company shall annually credit interest on the deposit at the Company's average short-term borrowing cost, as updated from time to time.

The deposit shall cease to draw interest at the earliest of; the date it is returned to the Customer, the date notice is sent to the Customer's last known address that the guarantee is no longer required, the date the deposit is applied against the outstanding indebtedness of the Customer, or the date when service is final billed.

In the event of termination of the contract between the Company and the Customer, such deposit plus accrued interest, less any amount owed to the Company, will be refunded.

8) Budget Billing Plan

The Company may, at its discretion, permit the Customer to pay fixed monthly installments on account of services and/or gas consumed or to be consumed by the Customer during all or any part of a period.

The Company shall fix the amount of the monthly installments on the basis that the installments to be paid shall total the sum which would be payable under the Company's rate schedule for the amount of gas or services which the Company estimates would be consumed on the Premises during the period in which the Customer is to pay such installments (herein called, "the budget period").

The Customer may terminate the Budget Billing Plan at any time by giving seven (7) days' prior notice of termination to the Company and the Company may terminate the Budget Billing Plan at any time in the event that the Customer ceases to be a Customer, or if the Customer has not maintained payment of installments to the Company's satisfaction.

Upon the expiration of the budget period or its earlier termination as referred to above, the amount that would be payable to the Company by the Customer pursuant to the rate schedule for gas actually consumed from the beginning of the budget period to its end or earlier termination, shall be compared with the aggregate of the monthly installments actually paid by the Customer during such time, and if the amount payable exceeds the aggregate of the amounts actually paid, such excess shall be paid by the Customer to the Company, or if the amount actually paid exceeds the amount payable, such excess shall be paid or credited by the Company to the Customer.

The Company may, at any time, revise its estimate of a Customer's gas consumption, and accordingly, may increase or decrease the amount of monthly installments payable by the Customer. In addition, the monthly installments may be adjusted to reflect approved rate changes.

9) Returned Cheques

When a Customer's cheque is returned by banks or other financial institutions for any reason, a returned cheque charge will be assessed to the Customer. The amount of this charge will be as determined from time to time by the Company, subject to Board approval.

10) Taxes

The rates and charges referred to in these Terms and Conditions do not include taxes or other amounts which the Company may be required to collect from Customers.

11) Late Payment Charge

A late payment charge shall be charged on the dollar amount owing after each billing due date. The due date will be at least 14 days after the mailing of the bills.

12) Measurements

The volume and gross heating value of gas shall be determined as follows:

a) **Unit of Gas**: The unit of gas sold to or transported for the Customer shall be a volume of gas measured according to Boyle's Law for the measurement of gas under varying pressures and on the measurement basis set out in paragraph b) below. Where appropriate, proper corrections shall be made for the specific gravity and flowing temperatures of the gas and for deviation from Boyle's Law as provided in paragraph b) below.

b) **Determination of Volume**, for the purpose of measurement, the unit of volume shall be one Cubic Meter of gas at a temperature of 15.56 degrees Celsius and at a pressure of 101.560 kilopascals absolute. For the purpose of measurement of gas delivered by the Company the average absolute atmospheric (barometric) pressure at such delivery points shall be assumed to be constant during the term thereof, regardless of variations in actual barometric pressure from time to time, and shall be assumed to be the following for each delivery point within the applicable Manitoba Sales Districts and Zones (see Section I: Territory Served):

Zone	**Average Absolute Atmospheric (Barometric) Pressure** (PSIA)
1	14.30
2	14.18
3	14.05
4	13.87

c) **The gross heating value** of the gas per Cubic Meter at any delivery point shall be as determined by TransCanada PipeLines Limited ("TCPL").

d) **The flowing temperature** of the gas shall be, in the case of non-orifice measurement devices, in accordance with the recommendation of the equipment's manufacturer. Integrating devices for automatically correcting volumes for flowing temperature may be used as the Company deems necessary.

e) **The specific gravity** of the gas delivered shall be as determined by TCPL.

f) **When gas is measured** by means of an orifice meter or meters, the factor for correction for deviation from Boyle's Law shall be computed in accordance with the American Gas Association's Tables published for that purpose together with amendments and supplements, using the daily arithmetic averages of temperatures, pressure, specific gravity, and a representative gas analysis as required by the tables. When gas is measured by means other than an orifice meter, the factor for correction for deviation from Boyle's Law shall be the square of the factor determined by following the above described method for use with orifice meters.

13) Determination of Monthly Billing Demand

The Monthly Billing Demand that will be used to calculate the Customer's Monthly Demand Charge shall be determined as follows:

a) **Monthly Billing Demand** will be the highest daily consumption, subject to sections V F) 3), V G) 7), VI D) 4), and VI E) 7), measured in Cubic Meters on any given day of the month, provided the month is a Winter Month, or in any Winter Month of the preceding eleven months. For Customers without twelve months of demand billing data, the Monthly Billing Demand may be estimated or otherwise specified by the Company.

b) **Exception**: During the months of November and March, the Company may (at its sole discretion) authorize certain Customers to use gas without invoking a higher Monthly Billing Demand. This flexibility will be available only to those Customers who do not regularly require significant volumes of gas in the Winter season, but whose non-winter requirements may extend into the Winter season for a short duration either at the start or at the end of the Winter season. Such flexibility may be provided at the sole discretion of the Company.

E) OTHER SERVICES

The Company may provide the following services:

a) Locate and mark at no direct charge, all Company owned underground plants on request to facilitate excavation or other construction.

b) Respond, at no charge, on a 24-hour emergency basis to reports of, explosion, fire, gas odour, leaks, fumes, over-pressure, overheating of natural gas space heating equipment or damaged plant, or any other service which, in the Company's opinion, is required for the maintenance and security of Company equipment.

c) Provide safety inspections, safety related adjustments and/or repairs to the natural gas burning portion of stoves, ranges, and all primary space and water heating residential and commercial appliances under 400,000 Btu/h (422 MJ/h). This includes, but is not limited to, repair of minor gas leaks, and the adjustment and replacement of controls and control parts. The Small General Class Customer will be responsible for the cost of parts. All other Customers will be responsible for the cost of parts and labour.

d) Service to commercial or industrial equipment over 400,000 Btu/h (422 MJ/h) will not normally be undertaken. The Company will respond, however, to commercial emergencies where business might be adversely affected by prolonged interruption of service. The Customer will be responsible for the cost of parts and labour.

e) Provide customers or customers' agents with basic billing. Routine queries for which a response can be developed with the commitment of 30 minutes or less of staff time will be addressed at no charge. For more complex inquiries, which require more than 30 minutes staff time, the customer will be responsible for the cost of labour, which will be billed at the approved Company Labour Rate (see Section XI, Company Labour Rate).

All “Other Services” provided by the Company to the Customer shall be charged to the Customer at rates in effect from time to time.

F) EQUIPMENT

1) Ownership of Equipment

The title to and ownership of all service lines, meters, regulators, attachments, and other Company equipment placed on the Customer’s Premises shall remain in the Company, with right of removal, and no charge shall be made by the Customer for use of Premises occupied thereby. This paragraph shall not apply to equipment sold directly to the Customer by the Company.

2) Measuring Station

The Company will install, maintain, and operate, at or near each delivery point, a measuring station properly equipped with a meter or meters and other necessary equipment for properly measuring the gas delivered.

Positive displacement and turbine meters together with auxiliary equipment shall be of a type approved for use by the Department of Consumer and Corporate Affairs, Standards Branch, pursuant to the Electricity and Gas Inspection Act (Canada). When positive displacement and turbine meters are used they shall be equipped with a counting device for indicating the actual volume of gas passing through the meter. A device for integrating the product of the volume of gas measured multiplied by the pressure and temperature corrections and indicating the volume of gas delivered may be used. If an integrating device is used, correction for the deviation from Boyle’s Law may be built into the device; otherwise such correction shall be applied to the volume of gas indicated at the Company’s sole discretion.

The Customer may install, maintain, and operate, at its own expense, such check measuring, pressure, or volume control equipment as desired, provided that such equipment shall be installed and/or operated so as not to interfere with the operation of the Company’s equipment.

3) Rights of Parties

The measuring equipment so installed by either party together with any building erected by it for such equipment, shall be and remain its property. However, the Company and the Customer shall have the right to have a representative present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other’s equipment. The records from such equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten days after receipt thereof.

4) Care Required

All installation of equipment applying to or affecting deliveries of gas shall be made in such manner as to permit an accurate determination of the quantity of gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by both parties in the installation, maintenance, and operation of equipment so as to prevent any inaccuracy in the determination of the volume of gas delivered.

5) Preservation of Metering Records

The Company, and where the Customer has installed check equipment, the Customer, shall each preserve for a period of at least six years all test data, charts, and other similar records. Microfilms of the original documents shall be considered true records.

6) Protection of Company -Owned Equipment on Customer's Premises

a) Maintenance of service lines, meters, and regulators or any other Company-owned equipment shall be the responsibility of the Company. The Customer shall be responsible for all damage to equipment on the Premises except for deterioration from normal usage.

b) If the Customer undertakes to renovate, reconstruct, or modify the Premises in such a way as to render Company equipment non-compliant with any existing codes or regulations, the Company will make any corrections necessary to its equipment so that it conforms to the said codes and regulations and the Customer shall be responsible for the cost of such corrections.

7) Moving Meters

The Company may charge the Customer the cost of moving a meter from one location to another in the event such move is made at the request of the Customer.

8) Access to Premises

In cases of perceived emergency, or for reasons of safety, or if the premises are uninhabited, the Company is authorized to enter upon the Premises in the absence of the Customer and is authorized to use such force as may be necessary to obtain access to its equipment for inspection, disconnection, and repair. All such instances shall be reported to the local police authorities immediately by the Company.

9) Termination of Service

If the supply of gas is terminated for any reason, the Company may, but shall not be obligated to, remove any or all Company owned equipment. Where the equipment is not removed, the Company shall effectively seal it off in compliance with applicable codes, regulations, and industry practices.

10) Rental Equipment

The title to all equipment supplied by the Company under a Rental Agreement and placed on the Customer's Premises shall remain with the Company with right of removal, and no charge shall be made by the Customer for use of Premises occupied thereby.

G) DISCONTINUANCE OF SERVICE

1) Requirement of Notice

If the Customer desires to discontinue the use of gas or to move from the Premises or in any way to terminate the contract, the Customer shall notify the Company of such intention and provide the Company with reasonable notice of discontinuance.

2) Reasons for Discontinuance

The Company reserves the right to temporarily or permanently discontinue the supply of and/or delivery of gas and/or to remove its property from the Customer's Premises, for any of the following reasons:

a) Failure, temporary or permanent, of the availability of gas;

b) Necessary repairs on any point on its system;

c) Non-payment by the Customer of any indebtedness to the Company when due;

d) Failure of the Customer to pay any guarantee deposit or increase thereof forthwith on demand;

e) Bankruptcy or insolvency of the Customer;

f) Use by the Customer of defective pipe, appliances, gas fittings, or installations contravening prescribed codes and regulations, or the demand by the Customer for the supplying of gas in such a manner as may, in the Company's opinion, be likely to lead to a dangerous situation;

g) Use of gas contrary to the terms of these Terms and Conditions or to any explicit Contract made with the Customer;

h) Misrepresentation by the Customer in relation to the use of gas or the amount consumed;

i) Moving of Customer from the Premises;

j) Inability of the Company to gain admittance to the Premises to replace the meter as required, or read the meter for a period of six (6) consecutive months;

k) Termination in any manner of the contract of service;

l) Discontinuance of the use of gas on the Premises;

m) Fire, flood, explosion, or other emergency in order to safeguard persons or property against the possibility of injury or damage;

n) Theft of Company property, services, and/or gas.

3) Reconnect Fees

On each occasion when gas service is discontinued at the Customer's request or as a result of failure of the Customer to comply with these Terms and Conditions, and the Customer subsequently requests that service be resumed to the Customer at the same Premises, a reconnect fee may be charged in addition to the Customers Basic Monthly Charge (if applicable) and Monthly Demand Charge (if applicable) for the period of discontinued service. In the event that the meter and regulating equipment and/or service line are removed and replaced on the same Premises within five years of removal, the Company may charge a fee for resetting the meter, regulator and installation of the service line. Until such charges, together with any other indebtedness of the Customer to the Company are paid, the Company may, at its discretion, refuse to reconnect the service or to supply gas.

H) RULES FOR TRANSFER OF CUSTOMERS BETWEEN CLASSES OR SERVICES

The following rules shall apply with respect to any customer that may elect to make an eligible change between customer classes or between service offerings.

1) Transfers Between Sales and Transportation Service

Customers that are currently receiving Sales Service and that wish to contract for Transportation Service must make a written request to the Company. All requests for such transfer of Service must be made no later than March 15 in any given year. The Customer must execute a Transportation Service agreement with the Company no later than June 30 of the same year. All transfers between Sales and Transportation Services shall become effective no later than November 1 of each year.

2) Transfers Between Transportation and Sales Service

Customers that are currently receiving Transportation Service and that wish to contract for Sales Service must make a written request to the Company. All requests for such transfer of Service must be made no later than March 15 in any given year. The Customer must execute an agreement with the Company no later than June 30 of the same year. All transfers between Transportation Service and Sales Service shall become effective no later than November 1 of each year.

3) Transfers Between Interruptible Class and Firm Service Classes

Customers that are currently receiving Interruptible Service and that wish to be provided Firm Service must make a written request to the Company. All requests for such transfer of Service must be made no later than March 15 in any given year. The Customer must execute an agreement with the Company no later than June 30 of the same year. All transfers between Interruptible Service and the applicable Firm Service customer class shall become effective no later than November 1 of each year.

I) RESPONSIBILITY OF PARTIES

1) Transfer of Risk, Title, and Possession

With the exception of Customer owned gas, title to the gas and all risk in respect thereto shall remain with the Company until the gas is delivered to the Customer at the Delivery Point, at which point title and risk shall pass to the Customer. The Company shall have the right to commingle gas delivered to it by or for a Customer with gas owned by the Company or others.

2) Damages to Equipment

The Customer shall be responsible for all damage to Company property on the Premises and agrees to notify the Company immediately of any damage occurring thereto, and shall pay the cost of any repairs to such Company property except where such damage or cost of repairs is attributable to normal usage.

3) Force Majeure

Notwithstanding any other term or condition contained within the Company's Schedule of Sales and Transportation Services and Rates or contracts for service, neither party shall be liable to the other for failure to carry out its obligations hereunder when such failure is caused by force majeure as hereunder defined. The term "force majeure" means civil disturbances, industrial disturbances (including strikes and lockouts), arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blockades, insurrections, failure or inability to secure materials, permits, or labour by reason of priority regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, flood washouts, explosions, breakage or accident to machinery or lines of pipes or pipelines, temporary failure of gas supply, an act or omission (including failure to deliver gas) of a supplier of gas to the Company, or any other causes or circumstances to the extent that such cause or circumstance was beyond the control of and occurred without negligence on the part of the party prevented from carrying out its obligations by the act of force majeure.

Any causes or contingencies which entitle a party to claim force majeure shall not relieve it from liability in the event of its concurring negligence, or in the event of its failure to use due diligence to remedy the situation or remove the cause in an adequate manner and with all reasonable dispatch, nor shall such causes and contingencies affecting the performance of the obligations hereunder relieve either party from the obligations to make payments of amounts then due or thereafter accruing due hereunder. It is understood and agreed that the settlement of strikes and lockouts shall be entirely within the discretion of the party affected.

Provided always however, that when the Customers consumption or ability to consume is not affected, the Customer shall not be entitled to rely upon the aforesaid Force Majeure provisions.

4) Waste of Gas

The Customer shall use due care to prevent any waste of gas and will immediately notify the Company in case of failure or deficiency of supply or leakage of gas.

J) CONSUMER EQUIPMENT

1) Description of Installation

In those cases where the Company deems it necessary, the Customer shall present, in writing, complete specifications of equipment, loads, location plans, piping, regulators, and other data required.

2) Customer's Equipment

Gas piping, fixtures, and appliances on the Customer's Premises must be installed at the expense of the Customer or owner of the property.

The Company may delay the construction of an extension and/or service until the Customer has completed the piping and installation of equipment necessary to receive and use service.

V. SPECIAL TERMS AND CONDITIONS: TRANSPORTATION SERVICE (T-SERVICE)

A) A Transportation Service agreement setting out Customer specific information shall be established between the Company and the Customer for Transportation Service under the High Volume Firm Class, Mainline Class, or Interruptible Class, having a minimum term of one year. The agreement shall remain in effect for successive periods of one year, unless written notice of termination is given by either party to the other at least 90 days prior to the expiration of the agreement or any renewal thereof.

B) Subject to the conditions set out in subsection V. A) hereof, High Volume Firm Class, Mainline Class, or Interruptible Class customers may elect to receive Transportation Service where the customer's daily nomination equals or exceeds 200 GJ under normal operating conditions, excluding shut-downs for routine maintenance activities and holidays.

C) The T-Service Customer shall deliver to the Company at the designated Receipt Point(s) and the Company shall receive from the T-Service Customer and transport a volume of gas, as determined in accordance with subsection D) hereof, from said Receipt Point(s) to the designated Delivery Point(s).

D) The volume of gas delivered by the T-Service Customer and received and transported by the Company shall, on each day, equal the quantity of gas consumed by the Customer at its facility on such day as determined by the Company's measuring stations located at or near the Delivery Point, less the volume of Backstop Gas (if any) sold to the Customer by the Company on such day pursuant to subsection G) hereof.

E) The Company shall not be obligated to transport, in any one day, any gas in excess of the Daily Contract Demand designated for delivery to each designated Delivery Point for each type of service.

F) The T-Service Customer shall pay for all gas delivered by the T-Service Customer and received and transported by the Company at the T-Service Rates approved from time to time by the Board.

G) In the event that a T-Service Customer fails or anticipates failure to deliver the necessary volume of gas to the designated Receipt Point:

1) The T-Service Customer shall promptly notify the Company if the Customer has reason to believe that deliveries of gas by or for the Customer to the Company at the Receipt Point(s) will be impaired in whole or in part. At such time, the Customer shall indicate whether it will require gas from the Company and the volume required during such period of impairment. If the Company is unable to provide Backstop Gas as requested by the Customer, the Customer shall be obligated to restrict it's consumption to the volume of gas it can deliver into the system.

2) On any day when, as a result of impairment, the T-Service Customer requires gas from the Company, the Company may, subject to availability of supply, sell to the Customer such quantity of Backstop Gas as is agreed between the parties, and the Customer shall pay for any Backstop Gas the greater of:

a) its appropriate share pro-rata with other T-Service Customers purchasing Backstop Gas, on such day, of the total cost, including all costs associated with purchasing and having that supply delivered to the Receipt Point. These charges are in addition to the normal T-Service Volumetric Charges; or

b) the equivalent Sales Service Volumetric Rate.

On such day, the Backstop Gas shall be deemed to be the first volumes delivered to the Customer.

3) Volumes delivered to the Customer as Backstop Gas shall be included in the determination of the Monthly Billing Demand.

H) The provisions of this paragraph shall only be applicable if service hereunder is pursuant to one of the Company's Interruptible Transportation services.

1) The Company may, at its sole option, on notice to the T-Service Customer, curtail or discontinue service hereunder down to the level of Firm Transportation Service (if any) to which the T-Service Customer is entitled. Such notice shall be made by telephone, electronic, or other communication device, or in person, and the Customer shall curtail its consumption of gas to the extent requested by the Company within two (2) hours of receipt of notice.

2) In recognition of the curtailable nature of Interruptible Service the Customer agrees, at their sole expense, to:

a) Install, maintain and have ready to operate at all times a stand-by fuel source of sufficient size and capacity to satisfactorily replace the natural gas energy supply furnished by the Company, and to,

b) Ensure that sufficient supplies of stand-by fuel are available at all times, and that the Customer has sufficient personnel resources available to operate the stand-by fuel system at any time upon notice from the Company, and to,

c) Utilize the stand-by fuel source in the event that the Company gives notice to the Customer of a curtailment of service.

3) In recognition of the Customer's service as Interruptible Transportation Service furnished by the Company hereunder, the Company shall not be liable for damages to person or property resulting from curtailment of service, or the Customer's failure to provide adequate stand-by equipment and fuel, or to use such equipment properly and sufficiently.

4) In the event that the T-Service Customer fails to comply with any such notice of curtailment, then the Company may at its option:

a) Physically discontinue Transportation Service hereunder during any period of curtailment; and/or

b) Charge and collect from the Customer for all gas received and transported hereunder during any such period at the Unauthorized Over-Run Delivery Charge, or such lesser amount per m^3 as the Company, in its sole discretion, may decide upon.

c) Charge and collect from the Customer the Firm T-Service Delivery rates for a 12 month period subsequent to the failure to interrupt. This provision shall not relieve the Customer from continuing to operate as, and meet all of the obligations of, an Interruptible Customer during this 12 month period. Continued failure to abide by the terms of Interruptible Service shall entitle the Company to return the Customer to Firm Transportation Service on a permanent basis.

5) The Company shall have the further right to curtail the transportation of gas hereunder without notice and without any liability whatsoever for any resultant damage to the Customer for any one or more of the following reasons:

a) Repairs to its distribution system; or

b) Transportation of gas being prevented or interrupted for any cause reasonably beyond the control of the Company.

c) For breach by the Customer of any of the terms and conditions hereof.

6) With respect to each Delivery Point(s), the T-Service Customer shall be subject to a monthly bill equal to the Basic Monthly Charge, the applicable Monthly Demand Charge, and Volumetric Charges for volumes delivered.

7) Volumes taken by the Customer in contravention of curtailment notice shall be included in the determination of the Monthly Billing Demand.

I) Where the T-Service Customer is entitled to both Firm and Interruptible Transportation Service to a particular Delivery Point, the volume of gas transported by the Company to such Delivery Point on any day shall be deemed to be transported firstly under Firm Service up to the level of Firm Daily Contract Demand, and secondly under Interruptible Service; provided, however, that if on any day, the Customer’s Interruptible Service is curtailed, the gas under Firm Service shall be deemed to have been transported, up to the time of curtailment, at an even hourly flow at a rate equal to the Firm Daily Contract Demand, divided by 24.

J) The T-Service Customer shall notify the Company by e-mail or fax, no later than 2:00 p.m. Winnipeg time on the day prior to delivery (except during periods when the Customer has advised the Company that no transportation service is required) of:

1) The Customer’s nomination for the following day with TCPL; and,

2) The Customer’s forecasted gas consumption and Nominated Volume for the following day.

Such Nominated Volume and forecasted consumption shall be deemed to remain in effect from day to day unless changed by the Customer and notice of such change is given to the Company in the manner aforesaid. If on any day in the event that the T-Service Customer's actual gas consumption for that day is to deviate from the forecasted gas consumption and Nominated Volume identified in J) 2. above the Customer shall notify the Company at the earliest opportunity of any such deviation, and the T-Service Customer shall make reasonable efforts to make the necessary forecast and nomination adjustments required with TCPL and the Company.

K) Prior to 10:00 a.m. Winnipeg time each day, the T-Service Customer will advise the Company by telephone, fax or e-mail of the meter reading at each Delivery Point as at 9:00 a.m. Winnipeg time on that day.

L) The T-Service Customer shall provide notice to the Company advising of the particulars of any authorized agent at law it has appointed to carry forth its obligations pursuant to the Transportation Service agreement identified in sub-section A.) hereof. Until further notice is provided by the T-Service Customer to the Company advising of any change to or termination of such agency appointment, the Company shall be entitled to rely upon any act or thing done, or document executed by the authorized agent pursuant to the Transportation Service agreement in the same manner and as though such act or thing had been done, or such document has been executed by the T-Service Customer. The T-Service Customer shall indemnify and hold the Company harmless against any and all claims relating to, arising out of or resulting from the actions of the authorized agent pursuant to the Transportation Service agreement.

M) In the event that a Sales Service Customer elects to become a T-Service Customer, the Customer will indemnify and save the Company harmless against any costs incurred by the Company upstream of the Receipt Point for which the Company is unable to obtain relief. The Company reserves the right to determine the level of capacity that may be released to the Customer or his agent.

N) The T-Service Customer hereby releases the Company from the Company's obligation to supply gas (except in accordance herewith) to the Customer for so long as the Transportation Service Agreement remains in force. If the Customer wishes to recommence purchasing gas from the Company, the Customer acknowledges and agrees that it will be treated in the same manner as a new Customer applying for Sales Service and will be subject to the provisions in Section IV. H) 2. hereof regarding requests for transfer from Transportation Service to Sales Service.

O) If the T- Service Customer or its authorized agent causes delivery imbalances relating to the delivery of gas to the Company's distribution system, the Company may impose any imbalancing costs or charges on the Customer.

VI. SPECIAL TERMS AND CONDITIONS: INTERRUPTIBLE SALES SERVICE AND INTERRUPTIBLE DELIVERY SERVICE

The provisions of this Section VI pertains to Interruptible Sales Customers (taking corresponding Interruptible Delivery Service) and Mainline Customers electing Interruptible Sales (in conjunction with Firm Delivery Service) provided by the Company.

A) A contract setting out Customer specific information shall be established between the Company and the Customer having a minimum term of one year. The agreement shall remain in effect for successive periods of one year, unless written notice of termination is given by either party to the other at least 90 days prior to the expiration of the agreement or any renewal thereof.

B) In recognition of the curtailable nature of Interruptible Service the Customer agrees, at their sole expense, to:

1) Install, maintain and have ready to operate at all times a stand-by fuel source of sufficient size and capacity to satisfactorily replace the natural gas energy supply furnished by the Company; and to,

2) Ensure that sufficient supplies of stand-by fuel are available at all times, and that the Customer has sufficient personnel resources available to operate the stand-by fuel system at any time upon notice from the Company; and to,

3) Utilize the stand-by fuel source in the event that the Company gives notice to the Customer of a curtailment of service.

C) Subject to subsection VI D) hereof, the Company shall sell and deliver to the Customer and the Customer shall purchase from the Company at the Delivery Point, natural gas for consumption by the Customer at its premises; provided that the Company shall not be obligated to sell or deliver to the Customer, on any one day, any gas in excess of the Interruptible Daily Contract Demand as specified in a separate agreement, or in any one hour, any gas in excess of the Maximum Hourly Flow.

D) In the event that the Company determines, in its sole discretion, that it cannot provide Interruptible Sales Service from its available supplies, the following provisions will apply:

1) If, prior to the commencement of any day or at any time during any day, the Company reasonably believes that it will, on that day, be curtailing Interruptible Sales and/or offering Alternate Supply gas at a price higher than the Base Rate for Supplemental Gas to Interruptible Customers, it shall notify the Customer to this effect and of the sale price of such Alternate Supply gas. The Customer may elect to purchase Alternate Supply gas on that day or decline service for that day, or portion thereof, and the Customer shall promptly notify the Company of its decision. If the Customer declines service for that day or portion thereof it shall cease consuming gas on such day or portion thereof.

2) If the Company is able to offer Alternate Supply gas to the Interruptible Customer at a price that is equal to or less than the Base Rate for Supplemental Gas to Interruptible Customers, the Company may provide Alternate Supply service without

notice to the Interruptible Customer, and the Customer shall pay the sale price of that gas supply plus the Alternate Supply Service Delivery Rate.

3) If, on any day, the Customer elects to purchase the Alternate Supply gas, the Customer shall pay the sale price of that gas supply plus the Alternate Supply Service Delivery Rate.

4) If, on any day, the Customer elects to purchase Alternate Supply the volumes delivered on that day shall not be included in the determination of the Monthly Billing Demand.

5) If, on any day, the Company is providing Alternate Supply Service and the Customer, having declined such service, continues to consume gas on that day, the Customer shall be subject to section E) 3) below.

E) The following provisions shall apply to the interruption of service under these Services:

1) The Company may, at its sole option, on notice to the Customer, curtail or discontinue service hereunder down to the level of firm service to which the Customer is entitled (if any). Such notice shall be made by telephone, electronic or other communication device, or in person, and the Customer shall curtail its consumption of gas to the extent requested by the Company within two (2) hours of the Company's issuance of the notice;

2) In recognition of the Customer's service as Interruptible Service furnished by the Company hereunder, the Company shall not be liable for damages to person or property resulting from curtailment of service, or the Customer's failure to provide adequate stand-by equipment and fuel, or to use such equipment properly and sufficiently;

3) In the event that the Customer shall fail to comply with any such notice of curtailment, then the Company may, at its option:

a) Physically discontinue service hereunder during such period of curtailment; or,

b) Charge and collect from the Customer for all Unauthorized Over-Run Gas delivered to the Customer during any such period at the Unauthorized Over-Run Gas Charge and/or Unauthorized Over-Run Delivery Charge, or such lesser amount per m^3 as the Company, in its sole discretion, may decide;

c) Charge and collect from the Interruptible Customer the High Volume Firm Service rates or other Firm Service rates as decided by the Company, for a 12 month period subsequent to the failure to interrupt. This provision shall not relieve the Customer from continuing to operate as, and meet all of the obligations of, an Interruptible Customer during this 12 month period;

d) Continued failure to abide by the terms of Interruptible Service shall entitle the Company to reclassify the Customer to Firm Sales Service on a permanent basis;

e) Return the Customer to Firm Service on a permanent basis if in the sole discretion of the Company, the Customer does not provide evidence and proof of the installation, maintenance and/or capability to reliably provide a stand-by fuel source sufficient to satisfactorily replace the natural gas energy supply provided by the Company. The Company reserves the right to make such a determination and to advise the Customer of the effective date of any such return to Firm Service.

4) The Company shall have the further right, without notice to the Customer, to curtail service hereunder for any of the following reasons:

a) For repairs to its distribution system;

b) By reason of service hereunder being prevented or interrupted for any cause reasonably beyond the control of the Company; or

c) For breach by the Customer of any of the terms and conditions hereof;

5) With respect to each delivery point, the Customer shall pay a monthly bill equal to the Basic Monthly Charge, the applicable Monthly Demand Charge, and Volumetric Charges for any and all volumes delivered;

6) The Company shall not be liable for damages, costs, loss or expense, whether direct, consequential, or otherwise, to person or property, resulting from curtailment of service hereunder or the Customer's failure to provide adequate stand-by equipment and/or fuel, or to use such equipment properly and sufficiently.

7) Volumes taken by the Customer in contravention of curtailment shall be included in the determination of the Monthly Billing Demand.

F) The provisions of these "Special Terms and Conditions" may be superseded by any requirements contained in the Interruptible Service Contract as required in paragraph A) herein.

G) Where the Customer is entitled to both Firm and Interruptible Sales and/or Delivery Service hereunder to a particular Delivery Point, the volume of gas transported by the Company to such Delivery Point on any day shall be deemed to be transported firstly under Firm Service up to the level of Firm Daily Contract Demand as specified in a separate agreement, and secondly under Interruptible Service; provided, however, that if on any day, the Customer's Interruptible Service is curtailed, the gas under Firm Service shall be deemed to have been transported, up to the time of curtailment, at an even hourly flow at a rate equal to the Firm Daily Contract Demand, divided by 24.

VII. SPECIAL TERMS AND CONDITIONS: WESTERN TRANSPORTATION SERVICE

A) Western Transportation Service provides for the transportation, storage, transmission, and distribution as appropriate, of Customer-owned Primary Gas from the Alberta border to the Customer's premises. The Company provides mandatory Supplemental Gas in conjunction with this service.

B) An executed Western Transportation Service Agreement is required to take this service. Customers in all classes are eligible for this service.

1) The Customer must be represented by a Broker authorized by the Board to sell natural gas.

2) The Customer must sign an Agency Agreement to be represented by that Broker. The Agency Agreement must, at a minimum, appoint the Broker as the Customer's sole and exclusive Agent to contract for the Customer's Primary Gas Supply, authorize the Broker to execute an Agreement for Western Transportation Service on behalf of the Customer, and where ABC Service is desired, authorize the Broker to execute an Agency Billing & Collection Agreement with the Company on behalf of the Customer. In the event that a Customer has signed multiple Agency Agreements with different Brokers, the Company shall accept the Broker firstly appointed by the Customer.

3) The Broker must sign and execute an Agreement for Western Transportation Service on behalf of the Customer and on its own behalf.

4) In the event that the Broker does not maintain Standard & Poor's BBB grade credit rating (or its equivalent of B++ or Baa) or better, ABC Service is mandatory.

5) Customers that wish to act as their own Broker must have estimated annual consumption of equal to or greater than 680,000 m^3 and must be authorized by the Board.

C) Participation in Western Transportation Service will commence on the first day of each calendar month.

1) Brokers will submit enrollment applications on behalf of Customers. The Company will notify the Broker if a Customer enrollment application is unacceptable to the Company.

2) Enrollment applications must be submitted using a format acceptable to the Company, acting reasonably. Enrollment applications must include a field that clearly identifies the date that each Customer executed their respective Agency Agreements with the Broker.

3) The Company reserves the right to accumulate enrollment applications in such a manner as to efficiently process and administer the enrollment of customers onto this service. In the event that the Company elects to accumulate multiple applications from a Broker, it shall process those applications no less frequently than once each week.

4) Brokers may submit enrollment applications no earlier than 75 days prior to the requested date for commencement of service.

5) Enrollment applications must be received by the Company no less than 45 days prior to the requested date for commencement of service.

6) A Customer's participation in Western Transportation Service with one Broker must be terminated by that Broker before the Customer can participate in that Service with a different Broker.

7) The Company will send a confirmation letter to each Customer whose enrollment is acceptable to the Company.

D) Brokers who choose to participate in Western Transportation Service must do so through to the end of each Gas Year.

E) A Customer's enrollment in Western Transportation Service is subject to the following:

1) A Customer may return to the Company's Sales Service for Primary Gas effective with the start of any calendar month, subject to the Company's ability to provide Backstop Gas on a best efforts basis and the Customer's requirement to pay any and all incremental costs related to the Company's provision of that Backstop Gas.

2) The Company will provide Backstop Gas on a best-efforts basis to any Customer whose Western Transportation Service Agreement is terminated, through the end of the current calendar month, after which time the Customer may return to the Company's Sales Service for Primary Gas in accordance with Article VII F) 1),or to Western Transportation Service.

3) A Customer may switch Brokers effective with the start of any calendar month, subject to the terms of their Agency Agreement.

4) A Customer may, through the enrollment process, switch between Western Transportation Service Agreements with the same Broker effective with the start of any calendar month.

F) The Broker is responsible for securing firm supply of Primary Gas and transportation to the Alberta Border.

1) The firm supply and necessary transportation to the Alberta Border must be adequate to meet the Maximum Daily Quantity established by the Company for Primary Gas, plus the amount needed to supply related Fuel Gas on the TransCanada PipeLine from the Alberta Border to the Company's distribution system. The ability to supply and transport the Maximum Daily Quantity must be maintained for every day that service is provided.

2) The Company may direct, dispatch or dispose of the firm supply in any manner it sees fit, consistent with prudent utility practice, and shall be entitled to pass good title in such gas.

3) The Company is not responsible for the cost of the firm supply or related transportation to the Alberta Border, or for any financial or other performance penalties that may be associated with such firm supply or related transportation.

G) The Company shall on each day nominate a quantity of Primary Gas (plus Fuel Gas) to be delivered on the next day by the Broker and accepted by the Company at the Alberta Border or at a designated point(s) of receipt acceptable to the Company in its sole discretion in accordance with the following terms:

1) Prior to any deliveries being made in accordance with the terms of this Service, the Broker shall provide the Company with the name, address, telephone number, facsimile number and e-mail address(es) of the Supplier[s], and the point[s] of receipt for deliveries. Such information shall be immediately updated as changes occur.

2) Where there are two or more Suppliers, the Broker shall indicate to the Company what percentage of total daily nominations is to be made to each supplier. Such information shall be immediately updated as changes occur.

3) The Company shall nominate by 12:00 noon Winnipeg time each day. The quantity that is nominated will be determined by the Company, taking into account the total gas requirements of the Broker (on behalf of the Broker's Customer(s)), its Maximum Daily Quantity, system operating conditions, the quantity of Fuel Gas required to transport Primary Gas from the Alberta Border to the Receipt Point, the availability of transportation on TransCanada and nominations required under its system supply contracts and other gas purchase agreements under which the Company obtains gas. The required quantity of Fuel Gas will be determined in accordance with the applicable TransCanada fuel ratio in effect from time to time, as approved by the National Energy Board of Canada. Such nomination may be changed from time to time during the Day, and the Broker shall promptly adjust its deliveries to accommodate such changes.

4) The Company will nominate directly to the Supplier. The Broker agrees to inform the Supplier in writing that all nominations made in accordance with this Service by the Company to the Supplier for the delivery of gas to the Company, shall be received by the Supplier as if made by the Broker, and that all gas delivered by the Supplier to the Company pursuant to such nominations shall be to the account of the Broker. If for any reason the Supplier is unwilling or unable to accept such nominations, the Company shall be entitled to make in its discretion such nominations directly to the Broker.

5) The Company will nominate the Broker's supplies in approximately the same proportion to the total gas requirements of the Broker (on behalf of the Broker's Customer(s)) as the Company's nominations of Primary Gas in relation to total requirements for the Company's Sales (including Western Transportation Service) Customers.

6) Unless otherwise agreed to by the Broker (on behalf of the Broker's Customer(s)), the maximum quantity of gas that the Company may nominate on any day is the Maximum Daily Quantity, plus Fuel Gas.

7) The Broker shall immediately notify the Company if the anticipated quantity of gas to be consumed by the Broker's Customer(s) significantly changes for any reason.

8)
   a) The Broker or its Supplier shall notify the Company as soon as possible, after receipt of the nomination, or change in nomination, if such nomination cannot be satisfied. In addition, the Broker shall notify the Company immediately upon becoming aware of any event that will alter or affect the deliveries of gas under this Service.

   b) Notice provided in accordance with paragraph a) above does not relieve the Broker from their obligations hereunder.

9) All such confirmations or notifications shall be made by telephone, facsimile or e-mail, and if given orally, shall be effective only if they are confirmed the same day in writing by way of facsimile or e-mail.

10) Where a Supplier notifies the Company that nominations relating to more than one such Broker will not be wholly satisfied, the Company shall allocate the shortfall among such Brokers in accordance with the instructions of that Supplier. Where the Supplier does not provide such instructions to the Company, the Company shall allocate the shortfall among the Brokers in proportion to each Broker's respective share of the total nomination made by the Company to that Supplier.

11) If, with respect to any day, a nomination is not accepted or if for any other reason, the Broker fails to deliver any of the nominated gas, then the special provisions for Backstop Gas under Western Transportation Service shall apply.

H) A monthly Gas Loan Mechanism will provide for cash payments between the Company and each Broker for the value of the difference between Primary Gas Delivered by a Broker and Primary Gas Billed to that Broker's Customers. The Gas Loan will be reconciled for each Gas Year, within two months following the end of that Gas Year,

1) The Gas Loan will be tracked separately for each Broker.

2) For each Broker, the Company will calculate the Quantity Difference between Primary Gas Delivered and Primary Gas Billed for each month.

   a) Primary Gas Delivered in the month will be measured as the quantity of gas received from Brokers at the Alberta Border during the month, but not including Fuel Gas provided by the Brokers.

   b) Primary Gas Billed in the month will be measured as the quantity of Primary Gas reported on bills issued by the Company to the Broker's Customers during that calendar month. Primary Gas Billed in the month may include consumption in a prior period, in accordance with the Company's billing practices.

   c) Where Primary Gas is measured in Gigajoules, the quantity of Primary Gas in Cubic Meters will be determined using the Gross Heating Value as determined by TransCanada.

3) The Value of the Gas Loan for each month will be calculated as the Quantity Difference in each month multiplied by the Company's average unit cost of Primary Gas in storage inventory at the commencement of the gas year.

4) The Value of the Gas Loan shall be payable each month.

   a) If the quantity of Primary Gas Delivered in a month exceeds the quantity of Primary Gas Billed in that month, the Company shall pay the Value of the Gas Loan to the Broker.

   b) If the quantity of Primary Gas Delivered in a month is less than the quantity of Primary Gas Billed in that month, the Broker shall pay the Value of the Gas Loan to the Company.

   c) The Company will issue a statement for the amount payable by the Company or the Broker, as the case may be, on the 15th day of the month following the month in which gas is delivered. If such day is not a Business day, such statement shall be issued on the first Business Day following such day.

   d) Remittances will be due and payable on the 20th day of the month following the month in which gas is delivered. If such day is not a Business day, such amount shall be due and payable on the first Business day following such day.

5) Following the end of each Gas Year, the Company will perform a reconciliation on the Gas Loan.

   a) The Annual Quantity Difference will be calculated by the Company as the sum of the differences between Primary Gas delivered and Primary Gas consumed during the Gas Year, plus or minus any Annual Quantity Difference carried over from the prior Gas Year. A net under-delivered position will be reflected as a negative Annual Quantity Difference, and a net over-delivered position will be reflected as a positive Annual Quantity Difference.

   b) For purposes of the annual reconciliation, the value of the gas loan security deposit remaining on account with the Company will be calculated as the sum of the monthly security deposits withheld from or repaid to brokers, plus the value of any Annual Quantity Differences carried over from the prior Gas Year.

   c) At the conclusion of each Gas Year, Brokers can elect one of two options: the Annual Quantity Difference may either be carried over into the following Gas Year, or settled financially.

   d) If Brokers elect to carry over the Annual Quantity Difference into the following Gas Year, that reconciliation is subject to the following conditions:

      i) The annual financial reconciliation will consist of a final payment that completely offsets the remaining net value of the Security Deposits withheld from and repaid to Brokers throughout the Gas Year, plus a final payment equal to the value of the Annual Quantity Difference;

ii) The value of the Annual Quantity Difference carried over into the following year will be calculated by multiplying the Annual Quantity Difference for the current Gas Year being reconciled, by the Company's average unit cost of Primary Gas in storage inventory at the commencement of the Gas Year following the Gas year being reconciled;

iii) The Company will include the Annual Quantity Difference carried over from the prior Gas Year in the determination of the next Gas Year's annual supply requirements;

iv) The Company will nominate, and the Broker will deliver, appropriate quantities to satisfy current Gas Year consumption requirements as well as any Annual Quantity Difference (positive or negative) carried over from the prior Gas Year; and,

v) If, for any reason, the Broker will not be providing Primary Gas in the following Gas Year, the Annual Quantity Difference will not be carried over into the following Gas Year, and the Broker will be required to settle the Annual Quantity Difference as described below in Sub-section (e).

e) If, for any reason, the Annual Quantity Difference will not be carried over into the following Gas Year, or if the broker will not be providing Primary Gas in the following Gas Year, then;

i) The annual financial reconciliation will consist of a final payment that completely offsets the remaining net value of the Security Deposits withheld from and repaid to brokers throughout the Gas Year, plus a final payment equal to the Value of the Annual Quantity Difference; and,

ii) The value of the Annual Quantity Difference will be calculated by multiplying the Annual Quantity Difference for the Gas Year by the Company's average unit cost of Primary Gas in storage inventory at the commencement of the Gas Year being reconciled.

f) If the remaining Value of the Gas Loan indicates an overpayment by the Broker, the Company shall pay that amount to the Broker with the next scheduled monthly transaction following completion of the reconciliation calculations.

g) If the remaining Value of the Gas Loan indicates an underpayment by the Broker, the Broker shall pay that amount to the Company with the next scheduled monthly transaction following completion of the reconciliation calculations.

6) With respect to the Gas Loan Mechanism, no interest will be charged or credited by the Company for the Value of the Gas Loan, except for interest that will be calculated on late payments.

I) BILLING AND PAYMENT

1) Sales Customers will be billed monthly for Supplemental Gas, Transportation to Centra, and Distribution to Customer at rates, as approved by the Board from time to time. Bills will be issued on the regular billing cycle established by the Company. Subject to the provision of Agency Billing and Collection Service as noted later herein, unless the Broker signs an Agency Billing and Collection Agreement with the Company, the Broker shall be responsible for billing the Customer for Primary Gas. Failure by the Customer who does not utilize the ABC service to pay that Broker's bill will not result in termination of service by the Company.

2) The Customer is responsible for all charges related to Western Transportation Service, including charges incurred by their Broker when acting as the agent for the Customer. Such charges include:

   a) Gas supplies nominated by the Company at the Alberta Border, or at designated point(s) of receipt as acceptable to the Company in its sole discretion, on behalf of the Customer.

   b) Payments for gas loaned to the Broker by the Company under the Gas Loan Mechanism, including interest where applicable.

   c) Payments for Backstop Gas provided to the Broker by the Company, including interest where applicable.

   d) Reimbursement of any penalties or charges imposed on the Company as a result of the Broker's malfeasance or nonperformance.

   e) Service fees charged to the Broker by the Company.

3) The liability of a Broker's Customers in relation to an obligation of their Broker shall be prorated by the Company among the Customers of that Broker, based upon the Company's determination of any relevant factors and circumstances. Each Customer's liability will be limited to its pro rata share, so determined.

4) Should the Broker fail to pay all of the amount of the Gas Loan Mechanism as herein provided when such an amount is due, interest shall accrue on the unpaid portion of the statement at a rate per annum equal to the Company's average short-term borrowing cost, as updated from time to time. If such failure to pay continues for ten days after such amount is due, the Company may use any financial security provided by the Broker to meet that obligation and may deduct and set-off such amounts from and against Primary Gas revenues collected by the Company on behalf of the Broker.

5) All remittances for the Gas Loan Mechanism will be accomplished via Electronic Funds Transfer. Remittances related to the Gas Loan Mechanism may be added to or netted against remittances related to ABC Service in order to accomplish a single transaction on the scheduled day in each month.

6) In the event an error is discovered in the amount billed for the Gas Loan in any statement deemed to be rendered, such error shall be adjusted within thirty (30) days of the determination thereof, provided that such claim shall have been made within sixty (60) days from the date of discovery of the error.

   a) Errors discovered within the same Gas Year will be included in the monthly Quantity Difference and Value of the Gas Loan during that Gas Year.

   b) Errors discovered after the close of the Gas Year will be treated as an Annual Quantity Difference, subject to the same conditions as specified for the Gas Loan Mechanism.

J) Broker participation in Western Transportation Service is subject to the following:

1) Only Brokers licensed and registered to do business in the Province of Manitoba, and authorized by the Manitoba Public Utilities Board to operate as a Broker in Manitoba are eligible to participate;

2) The Agency Agreement creating a valid agency relationship between the Broker and the Customer must be retained as set out by the PUB in the Code of Conduct for Direct Purchase Transactions, as may be amended from time to time upon Order of the PUB;

3) The Agency Agreement must authorize the Broker to fulfill all requirements otherwise required to be met by the Customer under this Part VII Special Terms and Conditions: Western Transportation Service and be enforceable;

4) The Broker must execute a Western Transportation Service Agreement with the Company on behalf of the Customer;

5) Brokers must obtain, and maintain in good standing, firm supply contracts and transportation to the Alberta Border, or at designated point(s) of receipt as acceptable to the Company in its sole discretion, sufficient to meet the Maximum Daily Quantity requirements, plus Fuel Gas on TCPL from the Alberta Border to the interconnect between TCPL and the Company, and the allowed annual Primary Gas requirements for each Customer as determined by the Company;

6) Representations and warranties, satisfactory to the Company, that the Broker complies with the licensing requirements of the Board, including regulation relating to gas supply and transportation, as may be amended from time to time;

7) The Company may reject service elections from Brokers whose supply is not documented or confirmed to the Company's satisfaction;

8) The Company is not responsible for damages to the Customer should the Broker fail to perform; and

9)

   a) The Broker must have a Standard & Poor's BBB grade credit rating (or its equivalent of either B++ or Baa) or better, or alternatively, or in addition to, a form of guarantee acceptable to the Company from a parent corporation with a Standard & Poor's BBB grade credit rating (or its equivalent of either B++ or Baa) or better, from a Canadian or United States credit rating agency recognized by the Company.

b) Alternatively, if the Broker is unable to meet the requirements set out in subparagraph 9 a) above, the Broker must provide credit support as reasonably determined and requested by the Company from time to time.

c) The Broker shall immediately notify the Company in writing in the event that such credit rating of either the Broker or its parent, whatever the case may be, falls below the aforementioned minimum credit standard.

K) The Company will remain the natural gas provider of last resort.

1) The Company will provide Backstop Gas on a best-efforts basis to Customers of Brokers whose registrations are revoked or whose Western Transportation Service Agreements are terminated.

2) Both the Customer and the Broker remain responsible for all obligations that arise by virtue of their participation in the Western Transportation Service, prior to the Customer's return to either the Company's Sales Service for Primary Gas, or to Western Transportation Service with a different Broker.

L) The Company will provide Backstop Gas in case of a failure of Broker supply on a best-efforts basis as follows:

1) If on any day, a nomination is not accepted or if for any other reason, the Broker fails to deliver gas to the Alberta Border, or at designated point(s) of receipt as acceptable to the Company in its sole discretion, then the Company shall use its best efforts to acquire gas to replace the failed supply with Backstop Gas.

2) In this event, the Company shall, in its discretion, charge the Broker and the Broker shall pay for all Backstop Gas acquired on its behalf at a rate which shall not exceed two times the incremental cost of the gas. The Broker and Customer acknowledge that this is not a penalty, but a reasonable pre-estimate of liquidated damages and organizational costs incurred by the Company.

3) If the Company is unable to acquire Backstop Gas then the Customer, on notice from the Company, shall immediately curtail the use of gas at its facility. Customers who continue to consume gas after notice from the Company will be subject to the Unauthorized Over-Run Gas Charge and the Unauthorized Over-Run Delivery Charge as defined in the Schedule of Sales and Transportation Services and Rates.

4) All obligations of the Broker and Customer to make up used but undelivered quantities of gas remain in place and other obligations and amounts due to the Company remain due and payable.

5) The Company shall report all instances where Backstop Gas is supplied, or requested but not supplied, to the Public Utilities Board.

M) SUSPENSION AND TERMINATION

1) The Company may, without prejudice to its right of termination, suspend its obligations hereunder with respect to any Customer which itself or through its Broker falls into arrears in any payments required under this Service by more than sixty (60) days, such suspension to last until payment is made to the Company of any outstanding amount. During such period of suspension, the Company shall, subject to its right to disconnect service to the Customer under the provisions of The Public Utilities Board Act, use its best efforts to acquire and sell gas to the Customer as Backstop Gas, with any alterations as may be necessary.

2) Except as otherwise provided in the Terms and Conditions of this Service, the Company may terminate its obligations if there is a material breach or default of any representation, warranty, or obligation of the Customer or Broker under the Terms and Conditions of this Service or any Western Transportation Service Agreement, which is not remedied within 10 days of the Company giving written notice of the breach or default to the Customer or Broker.

3) The Company may immediately terminate its obligations under this Service if one of the following events occurs:

   a) Performance by the Company of its obligations hereunder would be in contravention of any law or regulation or any order or decision of a regulatory body or governmental authority having jurisdiction; or

   b) The Broker shall be declared or adjudged bankrupt, or if an application is made in respect of the Broker under the Companies Creditors Arrangements Act (Canada), or if a liquidator, trustee in bankruptcy, custodian, receiver, receiver and manager, moderator or any other officer with similar powers shall be appointed in place of or for the Broker, or if the Broker shall commit any act of bankruptcy or institute proceedings to be adjudged bankrupt or insolvent or consents to the appointment or the institution of such proceedings or admits in writing to an inability to pay debts generally as they become due or becomes an insolvent person as such term is defined in the Bankruptcy and Insolvency Act (Canada); or if the Broker shall have liquidated, dissolved, wound up its affairs or otherwise ceased doing business.

4) In the event that the Company exercises its rights of termination under paragraph 2 or 3 of these provisions, the Company shall concurrently with the termination, or as soon as reasonably possible thereafter, give written notice to the Customer of the termination.

5) In the event that this Service or the Agreement under which it is provided is terminated, all outstanding obligations incurred under this Service by the Company, the Broker and/or the Customer which arise by virtue of the Broker's or the Customer's participation in this Service prior to such termination remain in full force and effect. The Company and the Broker shall have the right to withhold any payments due to the other party until its obligations accruing from the terminating Customer are met. As between the Company and the Broker, each shall have the right to set off any payments due to it by virtue of the Termination of the WTS

Agreement against amounts owing to the other pursuant to any Western Transportation Service/Agency Billing and Collection Agreement, or the Gas Loan Mechanism operated thereunder.

6) No waiver by either party or any default by the other party under this Service shall operate as a waiver of any future default, whether of a like or different nature.

VIII. SPECIAL TERMS AND CONDITIONS: AGENCY BILLING AND COLLECTION SERVICE (ABC SERVICE)

A) ABC Service allows a Broker to assign to the Company the right to render bills to Western Transportation Service Customers in respect of the amount payable by the Customers to the Broker for Primary Gas, and to collect from Western Transportation Service Customers the amounts so billed. The Company will provide a single bill to Customers that includes charges for volumes consumed by the Customer as Primary Gas, as well as the Company's charges for services provided by the Company.

1) In the event that the Broker does not maintain Standard & Poor's BBB grade credit rating (or its equivalent of B++ or Baa) or better, ABC Service is mandatory.

2) The Broker must sign an ABC Service Agreement with the Company in order to receive this Service.

3) Provision of this Service in no way makes the Company liable for any obligation incurred by a Broker.

4) The Company will be entitled to deal with Primary Gas charges collected from Western Transportation Service Customers in the same manner as it deals with its own funds. These funds shall not, at any time, be construed to be trust funds.

B) The Broker will provide to the Company the Broker's Primary Gas Price to be charged to the Broker's Customers.

1) The Broker's Primary Gas Price must be expressed in dollars per Cubic Meter of Primary Gas consumed by the Broker's Customers.

2) The Broker's Primary Gas Price for Customers may be changed effective with the beginning of each calendar month.

3) Changes to the Broker's Primary Gas Price must be provided to the Company 45 days prior to the effective date of such change.

C) Brokers may enroll Customers in ABC Service at the same time the Customers are enrolled in Western Transportation Service. Enrollment in ABC Service will automatically end when Western Transportation Service is terminated by the Customer, the Broker or the Company.

1) Brokers must group Customers such that all Customers in the Group are charged the same Broker's Primary Gas Price.

2) Changes in enrollment for ABC Service may be requested using the enrollment process for Western Transportation Service. The Company will inform the Broker whether it can accommodate the change in enrollment.

3) The Company will bill the Customer for gas sold by the Broker to the Customer. A tariff of $0.25 per customer per month will be paid by the Broker to the Company for the provision of this service.

D) Bills to any Customer will be issued according to the Company's billing cycle applicable to that Customer.

1) The Company will include the Broker's charges for Primary Gas on every bill for natural gas service which the Company renders to the Customer.

2) The Company will calculate the Broker's charges for Primary Gas in the same manner as it calculates its own Charges for Primary Gas, including the provisions for pro-ration of price changes during billing periods.

3) The Customer will make a remittance to the Company based on the total amount of charges on the bill.

4) The Company will be responsible for collecting the total amount of charges on the bill.

5) Payments made by Customers to the Company pursuant to bills rendered by the Company shall be made without any right of deduction or set-off and regardless of any rights the Customers may have against the Broker.

6) Nonpayment of any amounts designated as Primary Gas charges on the bill shall entitle the Company to the same recourse as non-payment of the Company's charges, and may result in termination of service by the Company.

7) The Company's late payment charges to Customers will apply equally to Primary Gas charges and other charges contained on the bill. No portion of these late payment charges will be remitted to the Broker.

E) The Company will remit to the Broker an amount equivalent to the Broker's charges for Primary Gas subject to the Company's right to deduct and set off any amounts owing to the Company by the Broker. Remittance shall be made by the Company to the Broker for a calendar month on or before the 20th day of the month following such calendar month. If such day is not a Business Day, such amount shall be due and payable on the first Business Day following such day.

1) Remittances will be based on the total Broker's charges for Primary Gas billed by the Company to the Broker's Customers in that calendar month. The remittance payable by the Company to the Broker for any calendar month will be calculated as the sum of total Broker charges for Primary Gas and any amounts payable for that month by the Company to the Broker under the Gas Loan Mechanism, less any amounts payable by the Broker to the Company, including but not limited to payments required pursuant to the Gas Loan Mechanism.

2) Where the amounts to be deducted under subparagraph (1) are greater than the sum of Primary Gas charges billed to the Broker's Customers and Gas Loan payments due from the Company to the Broker, the Company will invoice the Broker for the net amount to be paid by the Broker to the Company. Remittance shall be made by the Broker to the Company for a calendar month on or before the 20th day of the month following such calendar month. If such day is not a Business Day, such amount shall be due and payable on the first Business Day following such day.

3) Remittance under ABC Service will be made regardless of the payment status on the Customer's bill.

4) Remittance shall be made via electronic funds transfer.

5) The Company will issue a statement of the Primary Gas charges billed to the Broker's Customers on the 15th day of the month following the month in which gas is delivered. If such day is not a Business day, such statement shall be issued on the first Business Day following such day.

6) Any amount to be remitted hereunder and not remitted on or before the date on which it is due (the "due date") shall thereafter bear interest at an annual rate equal to the cost of the Company's average short-term borrowing cost, as updated from time to time.

7) Any taxes (other than the Company's income taxes) and other charges which may become payable on or in respect of any Billing Service Fee payable by the Broker hereunder shall be borne and paid by the Broker.

8) Nothing contained in these Special Terms and Conditions of Agency Billing and Collection Service shall operate to assign to the Company, or require the Company to bill or collect or remit, any amounts payable as between the Customer and the Broker, save and except such charges for Primary Gas as the Company shall calculate hereunder using the Broker's Primary Gas Price effective pursuant to this Service.

9) The Company may terminate service under this Service for reasons other than Customer non-payment if the Broker shall be declared or adjudged bankrupt, or if an application is made in respect of the Broker under the Companies Creditors Arrangements Act (Canada), or if a liquidator, trustee in bankruptcy, custodian, receiver, receiver and manager, moderator or any other officer with similar powers shall be appointed in place of or for the Broker, or if the Broker shall commit any act of bankruptcy or institute proceedings to be adjudged bankrupt or insolvent or consents to sue, appointment or the institution of such proceedings or admits in writing to an inability to pay debts generally as they become due or becomes an insolvent person as such term is defined in the Bankruptcy and Insolvency Act (Canada); or if the Broker shall have liquidated, dissolved, wound up its affairs or otherwise ceased doing business. In addition, the Company may immediately terminate this Service in the event of a breach of the Agency Billing and Collection Service Agreement that is not remedied within ten (10) days of the notice of such breach being provided. Notwithstanding the termination of ABC Service, each party shall continue to be liable to pay, on the terms herein specified, any amount accrued or accruing due by such party to the other at the time of termination, regardless of when such amount becomes payable.

IX. RATE SCHEDULES (BASE RATES ONLY – NO RIDERS)

Please see pages 1 and 2 of Appendix A as attached.

X. RATE SCHEDULES – ANNUAL RATES (BASE RATES PLUS RIDERS)

Please see pages 3 and 4 of Appendix A as attached.

XI. MISCELLANEOUS CHARGES FOR SERVICE

ABC SERVICE FEE

$0.25 per customer per month

COMPANY LABOUR RATES:

Please see Appendix B as attached.

DAMAGE TO COMPANY EQUIPMENT:

Materials, labour, equipment and cost of gas, including Damage Investigation and Damage Repair and the cost of all Appliance Relights necessitated by the damage or the repair thereof, as set out in Appendix B, Attached.

EQUIPMENT RENTAL RATE:

Various rates depending on equipment and customer class.

FURNACE SAFETY CHECK:

The charge for a safety check and tune-up of a natural gas furnace will be $50. There is no charge for the Company to investigate a situation involving the potential leakage of gas.

INSPECTION/REINSPECTION FEES:

Inspection or reinspection of a single replacement or additional residential appliance will be $35.00. All other inspections or reinspections (minimum charge of 1 hour) will be $55.00 per hour.

LATE PAYMENT CHARGE:

A late payment charge of 1 ¼% per month shall be charged on the dollar amount owing after each billing due date. The due date will be at least 14 days after the mailing of the bills.

MATERIALS:

Manufacturer’s listed price plus freight and taxes.

METER RELOCATIONS:

Various rates depending on size of meter.

METER TEST:

When a Customer requests a test for the meter, the charge will be $35 for a Residential Meter or $130 for a Commercial Meter. This charge includes the cost of the test performed, and the removal and replacement of the natural gas meter.

UNAUTHORIZED OVER-RUN DELIVERY CHARGE:

For delivery service taken in contravention of the Company's notice of curtailment, the applicable Unauthorized Over-Run Delivery Charge shall be equal to the greater of: firm LGS volumetric rate for Transportation to Centra and Distribution to Customer Service, or; a pro rata share with any other Customers in contravention of the Company's notice of curtailment of any incremental costs incurred directly or indirectly as a result of such contravention.

UNAUTHORIZED OVER-RUN GAS CHARGE:

For Unauthorized Over-Run Gas taken in contravention of any conditions set forth in these terms and conditions of service, the Company may charge the applicable delivery charge, plus the greater of either:

a) 1.5 times the settled maximum daily NGX AB-NIT Same Day Index (High) as reported in the Canadian Gas Price Reporter (CGPR) during the time period that the Customer was curtailed, or
b) the natural gas rate in dollars per cubic metre equivalent to 1.5 times the maximum daily terminal unbranded rack price for Furnace Fuel Oil in dollars per litre that was reported in Winnipeg during the time period that the Customer was curtailed, or
c) the cost to the Company of obtaining replacement gas for delivery to the designated receipt point on that day.

RECONNECT FEES:

On each occasion when gas service is discontinued and subsequently resumed to the same Consumer at the same Premises, a reconnect fee will be charged in addition to: (a) the Basic Monthly Charge, except where a customer is disconnected in accordance with Section G) 2) of the Terms and Conditions of Service; and (b) the Demand Charge (if applicable) for the period of disconnection. For purposes of establishing the Monthly Demand Charge, the Demand Charge billed during the last month that service was provided will apply.

Where a service reconnection takes place during regular business hours, a reconnect fee of $50 (plus GST) shall be charged. Where a service reconnection takes place outside of regular working hours a reconnect fee of $65 (plus GST) shall be charged.

In the event that the meter, regulation equipment and/or service line are removed and replaced on the same Premises within five years of removal, the Company may charge an additional fee equal to the cost of resetting the meter and regulator and installation of the new service line.

RETURNED CHEQUE CHARGE:

When a Consumer's cheque is returned by banks or other financial institutions for reasons beyond the control of the Company, a returned cheque charge of $20.00 will be assessed to the Customer.

SECURITY DEPOSITS:

Three highest months consumption to a maximum of $225.

TEMPORARY DISCONNECTION:

In situations where a Premise is renovated, demolished or altered such that temporary removal of the Company's equipment is required, the Company may charge a cost based fee for re-establishing the natural gas service.

SERVICE RELOCATIONS AND ALTERATIONS

Where a customer requests, or where the customer's conduct requires, that an existing meter, regulator and/or service line be altered or relocated (so that it follows a different route from that chosen by the Company when it was initially installed or alters the existing configuration), the Company may require and the Customer shall pay all costs associated with the alteration or relocation, including the material, labour, and equipment required to perform the alteration or relocation.

YARD SERVICES:

Materials plus 40% plus labour.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Domestic Load Growth Sensitivity; Page No.: 17-18

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 7.0, Domestic Load Growth Sensitivity, pages 17-18.

QUESTION:

Under the high load forecast was the probability of load growth among natural gas customers considered?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Domestic Load Growth Sensitivity; Page No.: 17-18

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 7.0, Domestic Load Growth Sensitivity, pages 17-18:

QUESTION:

If yes, please provide the high load forecast for both number of customers and use per customer by rate class; if not, please explain why not.

RESPONSE:

The “high” load forecast is calculated probabilistically using a 90th percentile point. The calculation of this is based on Manitoba Energy and Peak at the system level using historic load variability as described on page 44 of the 2013 System Load Forecast included as Appendix D of this submission.

Input level assumptions, such as differences in numbers of customers, are not explicitly projected when determining the “high” load forecast.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Domestic Load Growth Sensitivity; Page No.: 17-18

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 7.0, Domestic Load Growth Sensitivity, pages 17-18:

QUESTION:

Please provide historical data for the last 3 years showing number of customers by rate class that have converted from oil to natural gas, electric to natural gas for water heating and space heating, as well as from natural gas non-heating to heating customers.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Domestic Load Growth Sensitivity; Page No.: 17-18

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 7.0, Domestic Load Growth Sensitivity, pages 17-18.

QUESTION:

Please provide the forecast of number of customers who are expected to convert from oil or electric to natural gas water or space heating in the high, low and reference load growth scenarios. Please provide all analysis underlying the assumptions and forecasts included in the response.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Capital Expenditure Forecast; Page No.: 32

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 9.0, Capital Expenditure Forecast (CEF 12), page 32:

QUESTION:

Under the sector heading "Gas" and sub-headings "Customer Service and Distribution Domestic" and "Customer Care and Marketing Domestic", please provide an explanation of the activities, projects or assets that will be funded by the capital expenditures shown for 2013-2022.

RESPONSE:

Descriptions and justifications for each of the categories of capital expenditures can be found in the Capital Expenditure Forecast CEF12 filed in the response to PUB/MH I-061 and Manitoba Hydro Exhibit #10 from the 2012/13 & 2013/14 Electric General Rate Application (accessible electronically at the following link).

http://www.pub.gov.mb.ca/exhibits/mh-gra-2012-13-14/Capital_Expenditure_Forecast_CEF12.pdf

The specific page references are as follows:

Gas Customer Service and Distribution Domestic – page 83; and

Gas Customer Care and Marketing Domestic – page 85.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Capital Expenditure Forecast; Page No.: 32

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 9.0, Capital Expenditure Forecast (CEF 12), page 32:

QUESTION:

Please provide the capital investment in infrastructure necessary to support the customer growth is projected for Centra Gas Manitoba Inc. in the reference, high and low load growth scenarios; if no increase in infrastructure is required for these scenarios, please explain why the existing infrastructure is able to support the projected load growth.

RESPONSE:

While Centra has experienced a steady increase in the number of its customers, the aggregate load on the natural gas distribution system has not increased at the same rate due to the provision of natural gas energy conservation programs. Although this is observable on a system wide basis, some geographic areas of Centra’s service territory are experiencing accelerated load growth. The Corporation has met this localized load growth by using existing plant capacity and also with support of some minor system improvement projects. Recognizing that Centra may be approaching the capacity limits on some major transmission and distribution mains that were built decades ago, future system capacity and reliability requirements are under review. This could lead to increased investment in future years to accommodate future load growth, including the addition of new customers.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Capital Expenditure Forecast; Page No.: 32

PREAMBLE: Refer to NFAT Consolidate Integrated Financial Forecast (IFF12) Chapter 9.0, Capital Expenditure Forecast (CEF 12), page 32:

QUESTION:

Does the Capital Expenditure Forecast (CEF 12) include any expenditures for new or increased receipt point capacity at existing city gate interconnections with high pressure mainline natural gas transmission systems; if so, please provide a description of the facilities to be constructed or upgraded, associated costs and expected in service date(s).

RESPONSE:

In fiscal year 2012/13, Centra Gas Manitoba Inc. upgraded its existing interconnection with TransCanada Pipelines at the Ile Des Chenes gate station for the purpose of increasing the reliability of gas supply to the City of Winnipeg and communities north and east of Winnipeg. This project involved the installation of 220 meters of 30 cm diameter steel natural gas transmission pipeline and two 40 cm isolation valve assemblies. The total cost of this project was $964,000 and was put into service in August 2012.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.1; Page No.: 9-2

QUESTION:

Please provide a description (and annual quantification) for all "sunk costs" that have been incurred and are expected to be incurred before the June 2014 start of the study period. Provide these for each development plan.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.2.2; Page No.: 9-7

QUESTION:

Please explain how the 78-year length of the study period was determined.

RESPONSE:

As explained in PUB/MH I-154:

As described in Appendix 9.3, Section 1.2 of the NFAT submission, the total study life used in the economics analysis is 78 years. For the total study life, Manitoba Hydro combines two approaches – a 35-year detailed evaluation and a long-life asset evaluation which extends from the end of the 35-year study period to the end of the service life of proposed hydro-electric generation assets, as representing the longest-lived assets.

The economic lives of assets developed in the different development plans may extend well beyond the 35-year planning period. While natural gas-fired generation resources are estimated to have economic lives of 30 years, hydro-electric resources are estimated to last 100 years or longer, the "weighted average" life of the hydro-electric plants approximates 67 years when considering the different service lives of the mechanical and electrical equipment and the service lives of the concrete and earthen structures. For the 35-year study period, detailed forecast information related to the Manitoba Hydro system, is used.

For hydro-electric assets going into service around 2025, a 67 year life extends the study to 2092, which is 78 years from now. Extending the study period captures benefits and reinvestment costs of the assets throughout the life of the hydro-electric assets, allowing plans to be compared over the entire life of the longest lived asset.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.2.2; Page No.: 9-7

QUESTION:

Please explain how 35 years was chosen as the length of the "detailed evaluation" period.

RESPONSE:

A 35-year study period has typically been used for the “detailed evaluation” period as it provides a period which covers the addition of the next major resources and is long enough to identify and demonstrate the effect of both the costs and the benefits of major new resources, some of which are long lead-time and long life resources. Detailed forecast values are used for Manitoba Load, export prices, fuel costs, and financial indices during this period. It is recognized that the there is greater uncertainty in forecasts the longer the period of time used for study. The 35 year period establishes a basis for the recognition of the inherent characteristics of shorter and longer life resources.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.1; Page No.: 9-17

QUESTION:

Please explain why the "K22/C29" development plan was not selected for further analysis

RESPONSE:

Please refer to Manitoba Hydro’s response to CAC/MH I-117.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-15

QUESTION:

Please indicate how the "target" debt/equity ratio of 75%/25% was derived.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-15

QUESTION:

Compare the target debt/equity ratio to actual ratios over the past five years.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-16

QUESTION:

Provide the data underlying Figure 11.6 in electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.1.4; Page No.: 10-8

QUESTION:

Please provide any analysis and data that were used to calculate the probabilities underlying the high, low, and reference discount rates. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

Section 2.3.2 of Appendix 9.3 explains in detail how probabilities were derived for the low, reference and high discount rates.

The data and information used to calculate the probabilities underlying the high, reference and low discount rates is provided in the attached excel file.

http://www.hydro.mb.ca/projects/development_plan/bc_documents/lca/lca_195_attachment_1.xlsx

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1; Page No.: 2-39

QUESTION:

Please provide the data and analysis shown in Chapter 10 S-curve exhibits (e.g., Figure 10.11 through 10.21). Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2; Page No.: 9-13

QUESTION:

Please explain why "the closest representation of a “do nothing” option is the least-capital investment development plan, which is the All Gas development plan." Define the term "closest" and indicate whether other options were investigated.

RESPONSE:

The closest representation of a “do nothing” option is the least-capital investment development plan, which is the All Gas development plan because there is no “do nothing” option for meeting the electric load requirements of Manitobans for future years. Over time new power resources will be required for Manitobans due to load growth and due to the need to replace or refurbish ageing generation plant.

Expanding DSM much more to reduce load growth and even attempt to eliminate growth would in itself be a plan which is not a “do nothing” plan because of the investment in DSM that would be required. It would be unlikely that the investment per MW or GWh for such a large amount of load reduction would be less than a gas generation plus there is much less certainty of obtaining such amounts of DSM compared to obtaining the same amount form gas or hydro generation.

Furthermore, even elimination of load growth would still require investment in:

A) Replacement of existing generation which will need to be retired such as Brandon # 5 coal steam generation unit (1969 ISD), Selkirk #1 & 2 gas steam generation units (1960/61 ISDS) and Brandon # 6 &7 gas turbine units (2002 ISD)

B) Replacement or rehabilitation of existing hydro generation stations such as Pointe du Bois (1911 ISD), Great Falls (1923 ISD), Slave Falls (1931 ISD), Seven Sisters (1931 ISD) etc.

The term “closest” is intended to represent the concept that a “do nothing” option would not included any capital investment so “closest” would mean that which has the least capital investment. Other options for a least capital investment plan have been considered but none were found to have a lower capital investment, although many other plans were found to have a lower overall net capital and operating cost (i.e. many other plans would have a greater net benefits).

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2; Page No.: 9-13

QUESTION:

Please indicate whether the "incremental benefits" described in this section mean the two "revenue" categories found in Table 9.1.

RESPONSE:

The term "incremental benefits" described in Section 9.3.2, page 13 of Chapter 9 does not refer to the two "revenue" categories found in Table 9.1 of Chapter 9. The term "incremental benefits", in the context of the discussion in Section 9.3.2, refers to the incremental NPV difference between two development plans where the incremental NPV difference (or incremental benefit) is greater for a more costly option.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.3; Page No.: 9-25

QUESTION:

Please provide the calculations found in Figure 9.3 assuming that only 35 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.4; Page No.: 9-26

QUESTION:

Please provide the calculations found in Table 9.9 assuming that only 35 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.1.1; Page No.: 4

QUESTION:

Please provide all analysis Manitoba Hydro has performed to assess the Internal Rate of Return of the Preferred Development Plan.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.1.1; Page No.: 4

QUESTION:

Please provide all Manitoba Hydro policies regarding rate of return hurdle rates for new hydro generation assets.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.5; Page No.: 90-495

QUESTION:

Please provide Tables 1-405 in electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.5; Page No.: 90-495

QUESTION:

Please describe the calculations and inputs used to develop Tables 1-405.

RESPONSE:

Please refer to *Appendix 9.3 Economic Evaluation Documentation, Section 3 Economic Summary Tables* which provides a description of the calculations and inputs used to develop Tables 1-405.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.5; Page No.: 496-534

QUESTION:

Please provide Tables 406-444 in electronic spreadsheet format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.5; Page No.: 496-534

QUESTION:

Please describe the calculations and inputs used to develop Tables 406-444.

RESPONSE:

Please refer to *Appendix 9.3 Economic Evaluation Documentation, Section 3 Economic Summary Tables* which provides a description of the calculations and inputs used to develop Tables 406-444.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.1.2; Page No.: 33

QUESTION:

Please provide the "historical data" and "Current Bank of Canada policy" used to develop the high and low discount rates.

RESPONSE:

The historical data referenced in Section 2.1.2 is provided below; the current Bank of Canada policy is attached.

Table 326-0020 Consumer Price Index (CPI), 2011 basket, annual (2002=100)

Year	Index
1991	82.8
1992	84
1993	85.6
1994	85.7
1995	87.6
1996	88.9
1997	90.4
1998	91.3
1999	92.8
2000	95.4
2001	97.8
2002	100
2003	102.8
2004	104.7
2005	107
2006	109.1
2007	111.4
2008	114.1
2009	114.4
2010	116.5
2011	119.9
2012	121.7

BANK OF CANADA
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B A C K G R O U N D E R S

Monetary Policy

The Bank of Canada's mandate is to conduct monetary policy in a way that promotes the economic and financial well-being of Canadians. The Bank does this by regulating money and credit in the economy so as to preserve the value (purchasing power) of the nation's currency.

Monetary policy is focused on keeping inflation low, stable and predictable

Experience has shown that the best way to foster confidence in the value of money and to contribute to solid economic performance and rising living standards is by keeping inflation low, stable and predictable. In this sense, low inflation is not an end in itself, but rather the means to an end—a stable, growing, well-functioning economy.

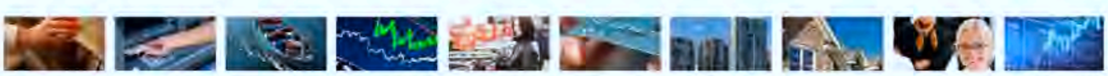
Low and stable inflation benefits Canadians in important ways. It creates an environment favourable to steady, healthy growth in output, employment and incomes over time. It gives Canadians greater confidence about the future, allowing them to make sound economic decisions. Specifically, it helps to encourage long-term investments that contribute to lasting economic growth, job creation and productivity gains that are critical to improvements in our standard of living. Low inflation preserves the purchasing power of Canadians, particularly those on fixed incomes, such as pensioners.

Canada's monetary policy framework

At the heart of Canada's monetary policy framework is the inflation-control target, which the Bank and the Government of Canada jointly adopted in 1991 and which they have since renewed five times—the latest one in November 2011 for another five years to the end of 2016. The target for inflation is the 2 per cent midpoint of a control range of 1 to 3 per cent.

Inflation is measured as the year-over-year rate of increase in the total consumer price index (CPI), which is the most relevant estimate of the cost of living for most Canadians. The Bank also monitors a set of "core" inflation measures, including the CPIX which strips out eight of the most volatile CPI components. These "core" measures allow the Bank to "look through" temporary changes in total CPI inflation by focusing on the underlying trend of inflation. In this sense, core inflation is monitored as an *operational guide* to help the Bank achieve the total CPI inflation target, not as a replacement for it.

The other important element of Canada's monetary policy framework is a flexible exchange rate. A floating Canadian dollar allows the Bank to pursue an independent monetary policy that is best suited to Canada's economic circumstances and is focused on achieving the inflation target. Movements in the exchange rate also provide a "buffer," helping our economy to absorb and adjust to external and internal shocks.



This text, and other backgrounders on topics related to the Bank of Canada's work, can be found at: bankofcanada.ca—search for "backgrounders."

1

B A C K G R O U N D E R S

How monetary policy works

The Bank carries out monetary policy through changes in its policy interest rate—the Target for the Overnight Rate.[1] The process by which these changes feed through to the economy and to prices is known as the "transmission mechanism of monetary policy." Changes in the policy rate work through several channels to determine the level of total demand and spending in the economy.

First, a change in the policy rate influences the whole range of market interest rates set by financial institutions, and thus borrowing costs for consumers, homebuyers and businesses, as well as the interest rate earned by savers on bank deposits, GICs, etc. Lower interest rates encourage people to save less and to borrow and spend more. Higher interest rates do the opposite. Second, changes in the policy rate can also influence the prices of assets, such as bonds, stocks and houses, thus increasing or reducing household wealth, which in turn may encourage or discourage spending. Third, a drop (or rise) in the policy rate in Canada relative to other countries may also make Canadian-dollar assets less (or more) attractive to investors, and this may lower (or raise) the exchange rate for the Canadian dollar. A lower value for the Canadian dollar boosts exports and restrains imports; a stronger dollar does the opposite.

When all is said and done, a reduction (increase) in the policy rate—i.e., an easing (tightening) of monetary policy—can be expected to boost (restrain) total demand for Canadian goods and services. But if total demand is too strong (weak) and the economy is operating above (below) its production capacity, this will push inflation consistently above (below) target, prompting the Bank to raise (lower) the policy rate to curb (bolster) spending and return inflation to target.

Monetary policy actions (changes in the policy rate) take time—usually between six and eight quarters—to work their way through the economy and to have their full effect on inflation. For this reason, monetary policy must always be *forward looking*. So, the policy rate is set based on the Bank's judgment of where inflation is likely to be six to eight quarters down the road (if policy action is not taken), not what it is today. This explains why the Bank may start raising (lowering) interest rates while, to all appearances, economic growth is still moderate (healthy) unemployment relatively high (low), and inflation tame (fairly high).

The Bank re-evaluates the outlook for the economy and inflation before each of its eight interest rate decisions a year. This reassessment involves a careful examination of the economic evidence accumulated since the previous interest rate decision, particularly with regard to the balance of supply and demand in the economy and other factors affecting underlying inflationary pressures. The lens through which the Bank assesses this information is focused on the achievement of the inflation target.

Consistent with its commitment to clear, transparent communications, the Bank explains regularly the rationale and implications of its interest rate decisions. And four times a year, it publishes a revised economic outlook in its *Monetary Policy Report*, outlining its perspective on the forces at work in the economy and their implications for inflation. Parliamentary appearances and speeches and interviews by Governing Council members are also part of the Bank's monetary policy communications.

1 When the policy rate is at its lowest possible level (the zero lower bound), as during the recent global financial and economic crisis, additional monetary stimulus to achieve the inflation target can be provided through a conditional statement about the future path of the policy rate and through two other non-traditional tools—credit easing and quantitative easing. The Annex in the April 2009 Monetary Policy Report describes these tools and the principles guiding their use.

This text, and other backgrounders on topics related to the Bank of Canada's work, can be found at: bankofcanada.ca—search for "backgrounders."

B A C K G R O U N D E R S

Canada's inflation-targeting approach is symmetric and flexible

Inflation targeting is *symmetric*

Canada's monetary policy functions *symmetrically* around the inflation target. In other words, the Bank is equally concerned about inflation rising above or falling below the target and will act to rein in or to boost demand in order to bring inflation down, or to push it back up, to 2 per cent. Such an approach guards against both high inflation and persistent deflation.

The Bank's *flexible* approach to inflation targeting

The Bank does not pursue the objective of low, stable and predictable inflation single-mindedly; nor does it stick to mechanical rules regardless of circumstances or economic costs.The Bank's inflation-targeting approach has always been flexible.

At times, shocks to the economy push inflation above or below target in ways that cannot be offset in the short run (given the lags in monetary policy), without risking significant volatility in output and inflation.[2]

In assessing the monetary policy actions that are needed under these circumstances to achieve the inflation target, the Bank must also make a judgment about the most appropriate horizon for returning inflation to target, so as to minimize the economic and financial volatility that these actions may cause. Such volatility can be harmful to the economic well-being of Canadians, which goes against the ultimate objective of a low-inflation policy.

2 Carney, M. 2011. "Renewing Canada's Monetary Policy Framework." Remarks to the Board of Trade of Metropolitan Montreal, Montreal, Quebec, 23 November.

The *flexibility* inherent in the inflation-targeting system practiced in Canada (and elsewhere) allows the Bank to adjust somewhat the typical two-year horizon for returning inflation to target—lengthening or shortening it, as appropriate, depending on the nature and persistence of the shock(s) hitting the economy. While this may mean sacrificing some inflation performance over the usual two-year horizon, it can lead to greater financial, economic and price stability over a somewhat longer horizon.

Broadly speaking, there are three sets of circumstances under which it may be desirable to return inflation to target over a somewhat longer-than-usual horizon.[3]

First, the effects of a shock could be sufficiently large and persistent that a longer horizon may be needed to provide greater economic and financial stability. Such considerations could, for example, lead the Bank to accommodate over a longer period the inflationary effects of a sharp, persistent increase in oil prices, or the disinflationary effects of a serious global economic slowdown, including the possible constraints of the zero lower bound on interest rates (ZLB).

Second, through a longer horizon, monetary policy can also promote adjustments to financial imbalances. For example, there could be instances when, even though inflation is above target, continued monetary stimulus and a somewhat longer horizon would be desirable to facilitate the adjustment to extensive deleveraging (running down of debts). Likewise, a tighter monetary policy that keeps inflation below target longer than usual could help to prevent excessive borrowing and a broader buildup of financial imbalances.

3 Bank of Canada. 2011. Renewal of the Inflation-Control Target: Background Information. (November).

This text, and other backgrounders on topics related to the Bank of Canada's work, can be found at: bankofcanada.ca—search for "backgrounders."

B A C K G R O U N D E R S

Third, the horizon may vary depending on whether the overall risks to the Bank's most likely outlook for inflation are seen to be on the downside or the upside and how much "risk management" the Bank deems appropriate to undertake. Simply put, when there is a relatively high risk that a negative shock will materialize, the Bank has the flexibility, through a longer-than-usual horizon, to "buy some insurance" against that risk and in this way minimize the associated adverse consequences.

During its 20 years of experience with inflation targeting, the Bank has made use of the flexibility to adjust the target horizon on several occasions. Typically, it has sought to restore inflation to target within six to eight quarters. There has, however, been considerable variation in the horizon, from as short as two quarters to as long as 11 quarters, depending on the shock(s). There have been nine occasions when the Bank has extended the target horizon beyond eight quarters.

The Bank's scope for exercising certain flexibility with respect to the target horizon is founded upon its demonstrated success and credibility in achieving the inflation target over time (since 1991, inflation has in fact averaged close to 2 per cent). This credibility is in turn best safeguarded by the Bank's continued commitment to, and success in, achieving the inflation target.

April 2012

This text, and other backgrounders on topics related to the Bank of Canada's work, can be found at: bankofcanada.ca—search for "backgrounders."

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 50-51

QUESTION:

Please provide the formulas underlying the calculation of real interest rate percentiles found in Table 2.7.

RESPONSE:

Please see the response to PUB/MH I-165(a).

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 51

QUESTION:

Please describe how the Manitoba Hydro inflation rates found in Figure 2.9 were derived.

RESPONSE:

As described on page 51 of Appendix 9.3, the high and low inflation rates found in Figure 2.9 are sourced from the Federal Reserve Green Book

http://www.fms.treas.gov/greenbook/index.html and the Bank of Canada Monetary Policy (a copy of which is provided in the response to LCA/MH I-207).

The reference forecast, labeled "MH med" in Figure 2.9 is Manitoba Hydro's consensus forecast. The high, reference and low values of inflation used in the NFAT analysis can be found in Appendix 11.2.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 51

QUESTION:

Provide the data underlying Figure 2.9 in electronic spreadsheet format.

RESPONSE:

Please see the attached excel file containing the requested data.

http://www.hydro.mb.ca/projects/development_plan/bc_documents/lca/lca_210_attachment_1.xlsx

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 53

QUESTION:

Provide the data underlying Table 2.8 in electronic spreadsheet format.

RESPONSE:

The requested information is provided in the attached excel file.

http://www.hydro.mb.ca/projects/development_plan/bc_documents/lca/lca_211_attachment_1.xlsx

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 55-56

QUESTION:

Please describe how the numbers in Figure 2.12 were derived. Compare these numbers (and any relationships) to the numbers found in Figure 2.11.

RESPONSE:

The information requested is provided in the attachment to LCA/MH I-195.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.3; Page No.: 60

QUESTION:

Please explain why the probabilities shown in Figure 2.15 differ among the three impact factors.

RESPONSE:

The probabilities for each of the three impact factors were assessed independently using available data and professional judgment.

Section 2.3 of Appendix 9.3 outlines the "Derivation of the Probability Weightings" for each of the three highest impact factors.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.4; Page No.: 62

QUESTION:

Please compare and contrast the probabilities shown in Figure 2.15 and the probabilities for NPV discussed on p. 62.

RESPONSE:

The NPV on page 62 of Appendix 9.3 is a hypothetical example of how to calculate expected value with one uncertain factor and three probabilities: 30%, 50% and 20%. It shows how expected value is calculated by multiplying probabilities and individual scenario values.

This calculation approach was applied to all 27 scenarios in Figure 2.15 of Appendix 9.3 (3 Energy Prices x 3 Discount Rates x 3 Capital Costs = 27 scenarios), each with its own combined or "joint" probability.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.7; Page No.: 67-69

QUESTION:

Please provide the data in Figures 2.7.1-2.7.3 in excel format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 11-3

QUESTION:

Please define the term "pathway" found in the table.

RESPONSE:

The term 'Pathway" used in the table on page 3 in Chapter 11 is the same term "Pathway" first explained on page 21 of the Executive Summary and then used extensively in Chapter 14. It is defined on pages 4-5 of Chapter 14.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 11-4

QUESTION:

Please explain the relationship (and any assumptions) between rate increases and reductions in Manitoba Hydro's debt-equity ratio.

RESPONSE:

Please see the responses to PUB/MH I-108 and PUB/MH I-183.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 11-7

QUESTION:

Please compare and contrast the "50-year study period" mentioned in this section and 78-year study period discussed in Chapter 9.

RESPONSE:

The financial evaluation in Chapter 11 is a full revenue and cost analysis of Manitoba Hydro's entire electric operations, including the impacts of the current and proposed integrated hydro-electric system, as compared to the incremental analysis, which includes the development plan specific inputs only, in the economic and uncertainy evaluations in Chapters 9 and 10. The 50-year period is an extension of the detailed 35-year evaluation period to be consistent with the long-term nature of hydro-electricity assets as well as provide a sufficient timeframe for which to analyze the benefits and costs for each development. Financial evaluation over a longer timeframe is limited due to the lack of availability of the detailed inputs and assumptions required by the financial model related to the entire integrated hydro-electric system both current and proposed rather than the availability of development plan specific inputs and assumptions.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 11-4

QUESTION:

Please define the term "even-annual rate increases" and describe how these increases were calculated.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 11-4

QUESTION:

Please explain why the 2031/32 time period was selected for achieving the target debt-equity ratio.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 11.3 Average Unit Revenue/Cost; Section: Average Unit Revenue/Cost; Page No.: 1-432

QUESTION:

Please provide the tables in Appendix 11.3 in excel format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 11.4 Pro Forma Financial Statements; Section: Volume 1, Volume 2; Page No.: 1-648

QUESTION:

Please provide the tables in Appendix 11.4 in excel format.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 11.3 Average Unit Revenue/Cost; Section: Average Unit Revenue/Cost; Page No.: 1-432

QUESTION:

Please provide the weightings (likelihood of occurrence for each table in Appendix 11.3.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 11.4 Pro Forma Financial Statements: Volume 1 of 2; Section: Vol 1; Vol 2; Page No.: 1-648; 1-648

QUESTION:

Please provide the weightings (likelihood of occurrence for each table in Appendix 11.4.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Volume: Chapter 11: Financial Evaluation of Development Plans; Section: 11.0-11.5; Page No.: 1-23

PREAMBLE:

QUESTION:

Please provide the data underlying Figures 11.1 through 11.9. Provide data in excel spreadsheet format.

RESPONSE:

Please refer to the attached Excel file.

This attachment is provided in electronic form only.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 10-11

QUESTION:

Please provide annual rate changes (comparable in detail to those found in Figure 11.2) for the most recent 10 years.

RESPONSE:

The following table provides Manitoba Hydro's annual average electric rate increases from 2000 to 2013.

2000/01	0.00%
2001/02	-1.90%
2002/03	0.00%
2003/04	-0.72%
2004/05	5.00%
2005/06	2.25%
2006/07	2.25%
2007/08	0.00%
2008/09	5.00%
2009/10	2.86%
2010/11	2.84%
2011/12	2.00%
2012/13	4.40%
2013/14	3.50%

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 8; 11

QUESTION:

Please provide and explain the method to convert the projected cumulative rate increases from years 2015-2062 shown in Figure 11.1 to the equivalent even-annual rate increases shown in Figure 11.3

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-13

QUESTION:

Please provide net debt and net fixed assets (comparable in detail to those found in Figure 11.5) for the most recent 10 years.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-16

QUESTION:

Please provide debt:equity ratios (comparable in detail to those found in Figure 11.6) for the most recent 10 years.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 11-18

QUESTION:

Please provide retained earnings (comparable in detail to those found in Figure 11.7) for the most recent 10 years.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 8

QUESTION:

Please provide all current documentation of the financial model used to create the rate impact forecast shown in Figure 11.1.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.3; Page No.: 44-46

QUESTION:

Please provide the last 10 years of energy received (in both MW and GWh) from imports and exports by source (i.e.: long-term contracts, diversity contracts, market purchases, etc.).

RESPONSE:

The question requests a record of energy imports and exports energy measured in MW and GWh. Energy is not measured in terms of MW so Manitoba Hydro is only able to provide the energy quantities in GWh as follows.

EXPORTS				
	Dependable GWh	Diversity GWh	Opportunity Bilateral GWh	Markets GWh
2003/04	5,831	400	545	190
2004/05	5,192	440	3,335	1,463
2005/06	3,603	441	3,567	6,736
2006/07	3,334	319	4,033	2,217
2007/08	3,118	803	1,260	5,839
2008/09	3,199	889	1,309	4,730
2009/10	2,397	866	2,594	5,003
2010/11	2,512	865	1,848	5,119
2011/12	2,487	1,255	1,923	4,579
2012/13	2,361	1,276	1,700	3,750

1

IMPORTS				
	Dependable GW	Diversity GW	Opportunity Bilateral GW	Markets GW
2003/04	6	72	9,152	397
2004/05	-	40	2,047	205
2005/06	-	57	66	682
2006/07	31	22	1,522	311
2007/08	6	1	112	352
2008/09	1	12	2	577
2009/10	61	120	10	801
2010/11	23	26	2	700
2011/12	33	27	4	664
2012/13	49	1	1	682

2

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.4; Page No.: 7

QUESTION:

Please provide all current import contracts and any draft copies of potential or proposed import contracts.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.4; Page No.: 7

QUESTION:

Please provide Manitoba Hydro's monthly historical exchange of power for each of the import contracts listed in Table 5.2 from the past ten years.

RESPONSE:

	Diversity Sales MWh	Diversity Purchases MWh
Apr-02	0	156,369
May-02	6,470	28,570
Jun-02	48,400	22,358
Jul-02	49,150	33,436
Aug-02	38,250	25,800
Sep-02	55,285	25,841
Oct-02	21,750	32,276
Nov-02	0	62,795
Dec-02	0	52,749
Jan-03	0	54,154
Feb-03	0	62,729
Mar-03	0	76,677
Apr-03	0	44,380
May-03	0	0
Jun-03	66,445	300
	Diversity Sales MWh	**Diversity Purchases MWh**
Jul-03	166,627	0
Aug-03	139,891	0
Sep-03	26,930	0
Oct-03	0	0
Nov-03	0	0
Dec-03	0	8,250
Jan-04	0	9,445
Feb-04	0	10,025
Mar-04	0	0
Apr-04	0	0

May-04	0	0
Jun-04	55,840	0
Jul-04	165,384	0
Aug-04	176,792	0
Sep-04	42,452	0
Oct-04	0	0
Nov-04	0	7,000
Dec-04	0	8,475
Jan-05	0	9,600
Feb-05	0	9,275
Mar-05	0	6,000
Apr-05	0	0
May-05	0	0
Jun-05	65,448	0
Jul-05	157,186	0
Aug-05	143,900	0
Sep-05	55,820	0
Oct-05	18,450	0
Nov-05	0	9,550
Dec-05	0	21,675
Jan-06	0	8,200
Feb-06	0	11,825
Mar-06	0	5,600
Apr-06	0	0
May-06	10,250	0
Jun-06	43,600	0
Jul-06	106,544	0
Aug-06	130,750	0
Sep-06	28,320	0
	Diversity Sales MWh	**Diversity Purchases MWh**
Oct-06	0	0
Nov-06	0	700
Dec-06	0	5,625
Jan-07	0	4,650
Feb-07	0	10,200
Mar-07	0	1,125
Apr-07	0	750
May-07	63,368	0
Jun-07	111,500	0
Jul-07	208,410	0

Aug-07	225,216	0
Sep-07	103,292	0
Oct-07	91,371	0
Nov-07	0	0
Dec-07	0	0
Jan-08	0	0
Feb-08	0	0
Mar-08	0	0
Apr-08	150	0
May-08	81,574	0
Jun-08	108,009	0
Jul-08	220,250	0
Aug-08	226,500	0
Sep-08	140,567	0
Oct-08	111,450	0
Nov-08	0	0
Dec-08	0	3,892
Jan-09	0	6,426
Feb-09	0	0
Mar-09	0	1,230
Apr-09	0	0
May-09	134,821	0
Jun-09	160,149	0
Jul-09	211,201	0
Aug-09	232,839	0
Sep-09	49,369	0
Oct-09	77,706	0
Nov-09	0	11,550
Dec-09	0	38,549
	Diversity Sales MWh	**Diversity Purchases MWh**
Jan-10	0	49,820
Feb-10	0	20,150
Mar-10	0	0
Apr-10	0	0
May-10	53,700	0
Jun-10	149,196	0
Jul-10	205,825	0
Aug-10	207,604	0
Sep-10	140,725	0
Oct-10	108,019	0

Nov-10	0	0
Dec-10	0	14,250
Jan-11	0	12,000
Feb-11	0	0
Mar-11	0	0
Apr-11	0	0
May-11	42,927	0
Jun-11	180,055	0
Jul-11	199,484	0
Aug-11	200,750	0
Sep-11	152,591	0
Oct-11	108,181	0
Nov-11	91,354	0
Dec-11	73,016	0
Jan-12	70,101	0
Feb-12	68,150	8,079
Mar-12	68,747	19,276
Apr-12	55,841	0
May-12	76,063	0
Jun-12	156,902	0
Jul-12	197,478	0
Aug-12	207,048	0
Sep-12	151,701	0
Oct-12	82,968	0
Nov-12	67,050	0
Dec-12	61,875	1,050
Jan-13	66,150	0
Feb-13	66,150	0
Mar-13	86,700	0
	Diversity Sales MWh	**Diversity Purchases MWh**
Apr-13	103,970	0
May-13	111,440	0
Jun-13	165,276	0

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3; Page No.: 46

PREAMBLE: Please provide a breakdown by year, to 2032, of both forecasted actual and maximum dependable energy from imports as defined by Manitoba Hydro under the following scenarios:

QUESTION:

No new generation or transmission

RESPONSE:

The maximum amount of imports that can be considered as dependable energy in accordance with the Generation Planning Criteria is included in the Dependable Energy Supply and Demand Tables. There is no difference between forecasted dependable imports and maximum dependable imports. The amount of imports included as dependable energy by year to 2032 assuming no new generation as found on pages 18 and 19 of Appendix 4.2 are shown in the following table.

Dependable Energy Imports by Year (GW.h @generation)

Fiscal Year	No New Resources
2012/13	3068
2013/14	3068
2014/15	3068
2015/16	3068
2016/17	3068
2017/18	3068
2018/19	3068
2019/20	3068
2020/21	3068
2021/22	3068
2022/23	3068
2023/24	3068
2024/25	3068
2025/26	3043
2026/27	3043
2027/28	3068
2028/29	3068
2029/30	3068
2030/31	3068
2031/32	3068

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3; Page No.: 46

PREAMBLE: Please provide a breakdown by year, to 2032, of both forecasted actual and maximum dependable energy from imports as defined by Manitoba Hydro under the following scenarios:

QUESTION:

Preferred Development Plan

RESPONSE:

The maximum amount of imports that can be considered as dependable energy in accordance with the Generation Planning Criteria is included in the Dependable Energy Supply and Demand Tables. There is no difference between forecasted dependable imports and maximum dependable imports. The amount of imports included as dependable energy by year to 2032 for the Preferred Development Plan as found on pages 22 and 23 of Appendix 4.2 are shown in Table 1.

Table 1: Dependable Energy Imports by Year (GW.h @generation)

Fiscal Year	Preferred Development Plan
2012/13	3068
2013/14	3068
2014/15	3068
2015/16	3068
2016/17	3068
2017/18	3068
2018/19	3068
2019/20	3068
2020/21	4460
2021/22	4738
2022/23	4738
2023/24	4738
2024/25	4738
2025/26	4738
2026/27	4738
2027/28	4738
2028/29	4738
2029/30	4738
2030/31	4738
2031/32	4738

It should be noted that for dependable energy planning purposes Manitoba Hydro has assumed that it will be able to import energy on the 750MW interconnection on a guaranteed basis at an average rate of 375 MWh/hr during the off-peak hours.

As Manitoba Hydro is not located within the MISO market footprint there is no guarantee that MISO surplus generation resources will be dispatched to serve an external load such as Manitoba Hydro even in off-peak hours in spite of the fact that the new interconnection will have a firm north flow rating of 750MW. MISO rules associated with serving load outside the MISO footprint are subject to change and Manitoba Hydro considers it prudent to derate the continuous import transfer capability of the interconnection for long term energy planning purposes.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: Sections 3-6; Page No.: 15-173

QUESTION:

Please provide all tables in Sections 3-6 of Appendix 4.2 in electronic Excel format with formulas still intact and readable.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.3; Page No.: 45; Appendix B Manitoba Hydro 2011/12 Power Resource Plan, Section: Dependable Supply and Demand Tables, page 32-33; Appendix 4.2 Manitoba Hydro Supply and Demand Tables, Section 3, page 16-17

QUESTION:

Please provide a breakdown of imports by source in Table 4.3 and the "Contracted Imports" category shown in the No New Generation System Firm Winter Peak Demand and Resources Table in Appendix B. Please explain any differences in numbers between Table 4.3, the No New Resources Case table in Appendix 4.2, and the No New Generation table shown in Appendix B.

RESPONSE:

The following tables provide the breakdown by contract of the Imports shown in Table 4.3 of Chapter 4 and the No New Resources Table provided on Page 16 of Appendix 4.2 and the Contracted Imports shown on Page 32 of Appendix B of the NFAT Submission - the 2011/12 Power Resource Plan No New Generation Winter Peak Capacity Supply and Demand Table.

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Table 4.3 and Appendix 4.2 Winter Peak Capacity, MW @ generation				
	2013/14	**2021/22**	**2022/23**	**2026/27**
Current Imports:				
NSP 200 MW Diversity	220			
NSP 150 MW Diversity	165			
NSP 350 MW Diversity		385	385	
GRE 150 MW Diversity	165			
Proposed Imports:				
GRE 200 MW Diversity		220	220	
Total Imports	**550**	**605**	**605**	**0**

Appendix B (2011/12 PRP) - No New Generation Table Winter Peak Capacity, MW@ generation				
	2013/14	**2021/22**	**2022/23**	**2026/27**
Contracted Imports:				
NSP 200 MW Diversity	220			
NSP 150 MW Diversity	165			
NSP 350 MW Diversity		385	385	
GRE 150 MW Diversity	165			
Total Imports	**550**	**385**	**385**	**0**

There is no difference between Table 4.3 and the No New Resources Table in Appendix 4.2 which are based on the 2012/13 Power Resource Plan. The difference between these tables and the table in Appendix B of the 2011/12 Power Resource Plan is the new 200 MW GRE Seasonal Diversity Agreement which was not included in the 2011/12 Power Resource Plan.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.3; Page No.: 46; Appendix B Manitoba Hydro 2011/12 Power Resource Plan, Section: Dependable Supply and Demand Tables, page 34-35; Appendix 4.2 Manitoba Hydro Supply and Demand Tables, Section 3, page 18-19

QUESTION:

Please provide a detailed breakdown of import sources for select years in Table 4.4 and the "Imports" category shown in the No New Generation System Firm Energy Demand and Dependable Resources (GWh) in Appendix B. Please explain any differences in numbers between Table 4.4, the No New Resources Case table in Appendix 4.2, and the No New Generation table shown in Appendix B.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.2.2; Page No.: 18-28

QUESTION:

Have the costs for integrating DSM been compared to other supply side alternatives? What is the $/MW cost associated with the DSM plan? Please provide all analysis and supporting studies. Where possible please provide supporting information in excel spreadsheet format with all formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.3; Page No.: 13-17

QUESTION:

Please provide any analysis that has been performed on the maximum deferral period for Keeyask G.S. and/or Conawapa G.S. to still allow Manitoba Hydro's resource needs to be met?

RESPONSE:

Analysis performed to date on the potential deferral period for Keeyask G.S. and/or Conawapa G.S. to still allow Manitoba Hydro's resource needs to be met, based on current planning assumptions including current diversity agreements, and maintaining principles in Manitoba Hydro’s Planning Criteria are included in Section 12.4 2013 Update – DSM Sensitivity and DSM Stress Test in the NFAT Business Case.

Subsequent to the filing of the NFAT submission, Manitoba Hydro agreed to undertake additional analysis on the All-Gas Plan and the Preferred Development Plan based on updated DSM forecasts of program savings and costs, which will be filed upon completion.

Manitoba Hydro has also agreed to complete economic analysis on a development plan intended to defer the need for new resources. This plan will include revisions to load forecast (including DSM) assumptions, extended diversity agreements beyond existing terms, increased dependable import assumptions beyond those included in Manitoba Hydro’s Planning Criteria, and a new US interconnection built exclusively for import to Manitoba.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.3; Page No.: 13-17

QUESTION:

Please provide any analysis that has been performed on the maximum deferral period for Keeyask G.S. and/or Conawapa G.S. to still allow Manitoba Hydro's resource needs to be met?

RESPONSE:

Analysis performed to date on the potential deferral period for Keeyask G.S. and/or Conawapa G.S. to still allow Manitoba Hydro's resource needs to be met, based on current planning assumptions including current diversity agreements, and maintaining principles in Manitoba Hydro's Planning Criteria are included in Section 12.4 2013 Update – DSM Sensitivity and DSM Stress Test in the NFAT Business Case.

Subsequent to the filing of the NFAT submission, Manitoba Hydro agreed to undertake additional analysis on the All-Gas Plan and the Preferred Development Plan based on updated DSM forecasts of program savings and costs, which will be filed upon completion.

Manitoba Hydro has also agreed to complete economic analysis on a development plan intended to defer the need for new resources. This plan will include revisions to load forecast (including DSM) assumptions, extended diversity agreements beyond existing terms, increased dependable import assumptions beyond those included in Manitoba Hydro's Planning Criteria, and a new US interconnection built exclusively for import to Manitoba.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: Section 3 - Manitoba Hydro Supply and Demand Tables; Page No.: 16

QUESTION:

In the No New Resources Case of the System Firm Winter Peak Demand and Capacity Resources (MW) Table shown in Appendix 4.2, please provide details on the 220 MW of "Proposed Imports" shown starting in FY2014/15.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.1; Page No.: 5

QUESTION:

Please detail all risks that "… the 750 MW interconnection may not receive regulatory approval." Please provide contingency plans if the interconnection approval is delayed for longer than one year or is denied.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.1; Page No.: 5

QUESTION:

Please provide all analysis that supports the statement "In the event that the interconnection does not proceed and the 250 MW MP Power Sales Agreement (PSA) is cancelled, Keeyask G.S. is still the logical choice for a new resource option to meet Manitoba's growing electricity needs." on page 5 of 51 of Chapter 15.

RESPONSE:

The August 2013 NFAT Submission contains the analysis supporting the statement "In the event that the interconnection does not proceed and the 250 MW MP Power Sales Agreement (PSA) is cancelled, Keeyask G.S. is still the logical choice for a new resource option to meet Manitoba's growing electricity needs."

From both a reference scenario and an expected value basis, Pathway 3 plans with Keeyask first are more economic than the All Gas, SCGT Conawapa and CCGT Conawapa plans (e.g. see Table 14.2, page 9 of Chapter 14). From a rates perspective, Keeyask Gas has lower long term rates than All Gas. Keeyask Gas has similar rates profile to Gas Conawapa in the long term and lower rates in the medium term (e.g. see Figure 11.1, page 8 of Chapter 11). Chapters 9 and 10 demonstrate that wind generation is not economic. Chapter 7 summarizes the screening of resources which indicates gas, Conawapa, Keeyask and wind are the most viable supply options. The Chapter 12 sensitivities indicate that increased DSM does not alter the economic rankings of the plans.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.1; Page No.: 5

QUESTION:

Please quantify the "sufficient notice" that would have to be given so that "the Keeyask G.S. construction timeline could be adjusted to correspond to a later ISD if conditions indicate, likely around 2023, and the value of all Keeyask G.S. efforts and expenditures would still be retained."

RESPONSE:

In general, the earlier a deferral of ISD occurs, the smaller the cost impacts of doing so.

Manitoba Hydro and the general civil contractor will be preparing to be ready to mobilize for a July 2014 construction start over the first six months of 2014. Current plans are to commit to the general civil contract early March 2014. From a cost minimization impacts perspective, and given the current timeframe of providing this response, it would be most advantageous to defer the ISD by early March or even earlier.

Given that the actual construction start is not committed under the General Civil Contract until all the required approvals have been obtained, a deferral of ISD prior to commencement of construction (July 2014) will be more amenable to cost minimization than after the construction starts.

During the first year of construction (July 2014 to July 2015) the construction activities primarily involve Stage I cofferdam, camp completion and South Access Road. During the second year of construction, construction will primarily involve structures excavation. If the project were to be deferred up to this point, theses activities could be completed and the remainder of the construction be undertaken at a later date. The main concrete pours start May 2016. Once the concrete pours begin it likely would be impractical to stop the project and defer the ISD. Thus the latest date it would be practical to defer Keeyask from 2109 would be May 2016. An example of a situation similar to this was that of Limestone Generation project which had commenced construction but then construction was deferred after the Stage I cofferdam had been constructed.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.2; Page No.: 8

QUESTION:

Section 15.2.2 discusses risks of Manitoba Hydro's export sales associated with the Preferred Development Plan from a "multitude of factors." Please characterize all factors associated with the export contract risk and all associated means that Manitoba Hydro will use to manage these risks. Please include all associated analysis, contract provisions, market products, and any other applicable methods used.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.2.1; Page No.: 8

QUESTION:

Please characterize all risks associated with the approval and timeline of the 250 MW interconnection option.

RESPONSE:

There is a risk that Minnesota Power may not receive US regulatory approval for the 250 MW interconnection option. In addition, there is a risk that regulatory approvals and construction may be delayed which would affect the planned in-service date of 2020.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.3.1; Page No.: 13-14

QUESTION:

Please detail the development expenses that Manitoba Hydro has incurred in advance of having executed a MISO Facilities Construction Agreement in order to realize the target ISD of the GNTL.

RESPONSE:

Manitoba Hydro is spending approximately 150k$/month associated with its share of the development expenses of the GNTL.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.3.3; Page No.: 16-17

QUESTION:

Please quantify any financial penalties or financial expenses that would be incurred by Manitoba Hydro through its export contracts for any delays or cancellations.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.1.1; Page No.: 18

QUESTION:

Please detail all adjustments Manitoba Hydro has made to its development plans for Keeyask, G.S. in part through what was learned from the Wuskwatim Project.

RESPONSE:

Please refer to Section 15.6.2 of the August 2013 NFAT Submission for adjustments Manitoba Hydro has made to its development plans for Keeyask, G.S. through what was learned from the Wuskwatim Project. These adjustments were also influenced from experiences with the Pointe du Bois rehabilitation project and through discussions with other developers across Canada.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.1; Page No.: 20

QUESTION:

Please explain how Manitoba plans to proceed if the potential listing of Lake Sturgeon under SARA is enacted.

RESPONSE:

The following is extracted from the Response to CAC/MH I-231b:

> A decision to list Lake Sturgeon on the Nelson River under the *SARA* would require strict protection and mitigation measures for the species. For the Keeyask environmental assessment and licensing processes, DFO has indicated that it is taking a precautionary approach to Lake Sturgeon protection, given the COSEWIC assessment from 2006. Manitoba Hydro expects that the DFO will continue to follow this approach for Conawapa.
>
> The precautionary approach being taken by the DFO means that the protection measures that would be incorporated into the conditions of a permit under the *Fisheries Act* are consistent with what could be required if it were listed under the *SARA*. Correspondingly, the mitigation measures for the effects of Keeyask and Conawapa will have to satisfy those strict requirements. If Lake Sturgeon are listed on the Nelson River, the project proponents – the Keeyask Partnership and Manitoba Hydro in the case of Keeyask and Manitoba Hydro for Conawapa – would apply for permits to construct and operate the project.

If Lake Sturgeon are listed on the Nelson River, Manitoba Hydro (along with the Cree First Nations), would review the situation regarding designation of Lake Sturgeon Critical Habit and the likely distribution objectives for the reaches of the river associated with Keeyask and

Conawapa respectively. It is anticipated that the majority of what might be required under a SARA listing would already be undertaken and/or planned to be undertaken for Keeyask and Conawapa because the majority of the conditions of an authorization(s) under the *Fisheries Act* are expected to be consistent with what could be required if Lake Sturgeon were listed under the SARA. Furthermore, extensive Lake Sturgeon stewardship would already be proactively undertaken and/or planned even without a listing under SARA.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.1; Page No.: 21

QUESTION:

Please characterize the length of delay, financial implications, and project timeline effects that would occur if the Government of Manitoba adopts the recommendation that "Manitoba Hydro, in cooperation with the Manitoba Government, conduct a Regional Cumulative Effects Assessment for all Manitoba Hydro projects and associated infrastructure in the Nelson River sub-watershed." Also, please expand on when a decision would be made by the Government of Manitoba regarding this recommendation.

RESPONSE:

The Minister of Manitoba Conservation and Water Stewardship (MCWS) has committed to implementing all recommendations in the CEC's Bipole III Report, including non-licensing recommendation 13.2 which is cited above. Since the Minister's decision in early fall, staff at Manitoba Hydro and Manitoba Conservation & Water Stewardship have been discussing the most appropriate way to proceed with meeting the intent of this recommendation.

Manitoba Hydro does not know if there will be a delay but if there is a delay and it is one year long, the one year delay (regardless of the reason) would add approximately $300 million to the in-service cost of Keeyask. This includes one extra year of project cost, additional interest and escalation and was rounded up to the nearest $100 million.

If such a delay situation arose, the impact on the economics of the plan would be somewhat reduced. While the specific cost of such a delay is not known, Table 10.2.4, in Chapter 10, page 53 of the NFAT submission, indicates that a one year delay in the in-service dates of both Keeyask and Conawapa would result in a $97 million NPV cost in the reference scenario.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.2; Page No.: 22

QUESTION:

Please explain how Manitoba Hydro would proceed if the Comprehensive Study Report (CSR) determines Keeyask G.S. will cause a significant adverse effect and the Governor-in-Council concludes the adverse effect is justified in the circumstance.

RESPONSE:

The Keeyask Hydropower Limited Partnership has taken extensive measures to avoid, mitigate and offset adverse effects such that it believes there are no significant adverse project effects. It would be very concerned if the Comprehensive Study Report determines the Keeyask Generating Station will cause a significant adverse effect. If this occurs, and the Governor-in-Council concludes the adverse effect is justified in the circumstance and, assuming a Manitoba Environment Act License is also received for the Project, the Partnership will seek all reasonable and available opportunities to address the identified significant adverse effect before proceeding with the development of the Project.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.3; Page No.: 24

QUESTION:

Please provide all analysis that has been conducted to evaluate the financial costs and risks of cancelling or delaying the construction as well as all project risks associated with provisions implemented by SARA if a federal decision on SARA does not occur until after June 2014.

RESPONSE:

Please refer to CAC/MH I-231b, PUB/MH I-080b and LCA/MH I-261 for discussion of the risk of delay due to a SARA listing of Lake Sturgeon.

As discussed in the above responses, it is anticipated that the majority of Lake Sturgeon measures proposed by the KHLP would already be underway or being planned for due to the requirements of the Fisheries Act and due to proactive Lake Sturgeon stewardship by the provincial government, Manitoba Hydro and the local First Nations. Please refer to Appendix 2.1 for a summary of Lake Sturgeon stewardship.

The KHLP has had extensive discussions with the Department of Fisheries and Oceans (DFO) about habitat compensation and potential passage requirements for Lake Sturgeon, as well as other fish species. A number of specific mitigation and compensation measures for Lake Sturgeon have already been identified by the KHLP, consistent with the discussions with the DFO, and are described in detail in the environmental filings for the Keeyask Project and factored into the Project costs. This includes designing and constructing the generating station in a manner that would allow it to be retrofitted to accommodate other upstream and/or downstream fish passage options, if required, in the future.

There is a residual risk that some additional measures could be required if a decision on SARA does not occur until after June 2014, and the decision is to list the species as endangered. However, the cost of those additional measures is not known at this time; as well, it is considered unlikely that Nelson River Lake Sturgeon will be listed.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.5.2; Page No.: 29-30

QUESTION:

Please explain why the Design Build, Design Bid Build, and Integrated Design Build project delivery methods were not chosen for the delivery of the Keeyask GCC.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.7; Page No.: 47

QUESTION:

How much money is allocated in the Labour and Escalation Management Reserve Fund and what is the percentage in the fund when compared to total project costs?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix B Manitoba Hydro 2011/12 Power Resource Plan; Page No.: 13; Chapter 5: The Manitoba Hydro System Interconnections and Export Markets, Section 5.1.4, page 7

QUESTION:

Please reconcile the Winter Peak Capacity (MW) of 500 MW from Imports listed in Table 1 of Appendix B with the current import contracts totaling 500 MW capacity in Table 5.2 in Chapter 5.

RESPONSE:

The following tables show the contracts included in Imports shown in Table 1 of Appendix B (550 MW) and the Current Import Contracts shown in Table 5.2 in Chapter 5 (500 MW). As shown in the tables the same contracts are included in each import total. Chapter 5 Table 5.2 represents total imports at the delivery point and Appendix B Table 1 represents total imports at generation which also includes system losses.

Chapter 5 Table 5.2 @ South	
Contract	**Capacity (MW)**
NSP 150 MW Diversity	150
NSP 200 MW Diversity	200
GRE 150 MW Diversity	150
Total	**500**

Appendix B Table 1
@ Generation

Contract	Capacity (MW)
NSP 150 MW Diversity	150
NSP 200 MW Diversity	200
GRE 150 MW Diversity	150
Subtotal	500
Losses (10%)	50
Total	**550**

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.1; Page No.: 4

QUESTION:

Regarding the "Ease of Integration into System" technical characteristic, provide all documentation and analysis supporting the consideration of "intermittency, size and dispatchability" as factors in the resource screening process.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.1; Page No.: 4

QUESTION:

Regarding the "Ease of Integration into System" technical characteristic, provide all documentation and analysis supporting the statement that "the intermittency of wind only becomes an issue when the amount of wind variability exceeds the amount of load variability that occurs moment by moment." Provide all documentation and data quantifying Manitoba Hydro's load variability and any studies analyzing potential variability of wind projects in Manitoba. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

Pages 63 to 68 of a reference cited in Appendix 7.2, "2011 Wind Technologies Market Report" by the U.S. Department of Energy dated August 2012, provide an expanded discussion of the issue of ease of integration as it relates to high level screening. This document can be found via the following link:

http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf

Please also see Manitoba Hydro's response to LCA/MH I-409.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.1; Page No.: 4

QUESTION:

Regarding the "Ease of Integration into System" technical characteristic, provide any documentation, analysis, or reports demonstrating how Manitoba Hydro currently addresses the "dispatchability needed to complement the variability in water flows and loads" of the current hydraulic system. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

Chapter 5, Section 5.1.2 of the NFAT Business Case discusses how dispatchable thermal generation complements the variability of water flows. In general, when water inflows are low, thermal generation can be used to replace unavailable hydraulic generation. This is demonstrated in the following table which, for the period from 1980/81 to 2012/13, provides the actual annual generation for the hydroelectric and thermal resources in the Manitoba Hydro system, the percent of average annual inflows indicating the relative amount of inflow and the percent thermal gross generation indicating the proportion of thermal generation relative to hydroelectric generation. The table shows that in low flow years such as 1987/1988, 1988/1989 and 2003/2004 (highlighted in bold) the proportion of thermal generation is generally higher than in years with higher inflows and more available hydroelectric generation.

	HYDRAULIC GENERATION			THERMAL GENERATION		
Report Period	Maximum Continuous Rating (MCR) [MW]	Gross Annual Hydraulic Generation [MW.h]	Percentage of Annual Average Inflows	Maximum Continuous Rating (MCR) [MW]	Gross Annual Thermal Generation [MW.h]	Percentage Thermal Gross Generation
1980/1981	3,644	18,268,655	79%	639	340,174	1.8%
1981/1982	3,644	17,596,152	70%	639	463,142	2.6%
1982/1983	3,644	21,554,288	98%	639	89,381	0.4%
1983/1984	3,644	21,904,814	91%	639	103,307	0.5%
1984/1985	3,644	20,969,572	84%	639	356,631	1.7%
1985/1986	3,644	23,130,037	119%	639	156,488	0.7%
1986/1987	3,644	23,958,287	107%	639	99,131	0.4%
1987/1988	**3,644**	**18,034,063**	**66%**	**639**	**814,590**	**4.3%**
1988/1989	**3,644**	**15,237,085**	**59%**	**639**	**864,124**	**5.4%**
1989/1990	3,644	18,673,401	80%	639	432,251	2.3%
1990/1991	3,644	20,565,096	76%	639	288,563	1.4%
1991/1992	4,182	23,626,305	79%	639	320,690	1.3%
1992/1993	4,720	27,607,505	102%	639	206,758	0.7%
1993/1994	4,988	27,199,075	93%	639	249,196	0.9%
1994/1995	4,988	27,915,271	88%	639	206,164	0.7%
1995/1996	4,988	29,114,870	90%	639	195,654	0.7%
1996/1997	4,995	31,679,431	122%	639	163,003	0.5%
1997/1998	4,995	33,759,942	134%	507	273,063	0.8%
1998/1999	5,002	29,110,681	84%	507	932,254	3.1%
1999/2000	5,002	29,470,532	96%	507	675,023	2.2%
2000/2001	5,002	31,826,328	107%	507	860,433	2.6%
2001/2002	5,002	32,152,125	109%	507	480,522	1.5%
2002/2003	5,009	28,566,727	90%	507	600,700	2.1%
2003/2004	**5,009**	**18,484,120**	**62%**	**507**	**853,399**	**4.4%**
2004/2005	5,014	31,122,895	121%	507	413,511	1.3%
2005/2006	5,021	37,218,340	168%	507	401,460	1.1%
2006/2007	5,021	31,610,167	101%	507	521,607	1.6%
2007/2008	5,021	34,897,338	126%	447	456,507	1.3%
2008/2009	5,034	34,193,402	120%	447	334,705	1.0%
2009/2010	5,067	33,817,965	141%	447	142,997	0.4%
2010/2011	5,080	34,037,201	131%	447	65,891	0.2%
2011/2012	5,093	32,606,837	129%	447	77,109	0.2%
2012/2013	5,106	33,149,204	105%	447	83,215	0.3%

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.1; Page No.: 4-5

QUESTION:

Regarding the "Ease of Integration into System" technical characteristic, provide all documentation and analysis demonstrating that Manitoba Hydro's contingency reserve requirements apply differently to a 600 MW unit than they would to six 100 MW units. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

The rules of contingency requirements do not apply any differently on the basis of unit size up to the size of the largest single largest contingency. As stated in the NFAT Business Case, Appendix 5.2, Page 2, MISO carries a total of 2,000 MW of contingency reserves at all times.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.3; Page No.: 8

QUESTION:

Regarding the "Proximity to Load Center" characteristic, provide all documentation supporting the specific designation of the five categories of distances and explain how these categories were factored into the screening process. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.3; Page No.: 8

QUESTION:

Regarding the "Proximity to Load Center" characteristic, provide all documentation supporting the use of the Dorsey Converter Station as the proxy location. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.3; Page No.: 9

QUESTION:

Regarding the "Social Acceptability" characteristic, provide the two reference public opinion polls conducted by Ipsos and the Innovative Research Group.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-084.

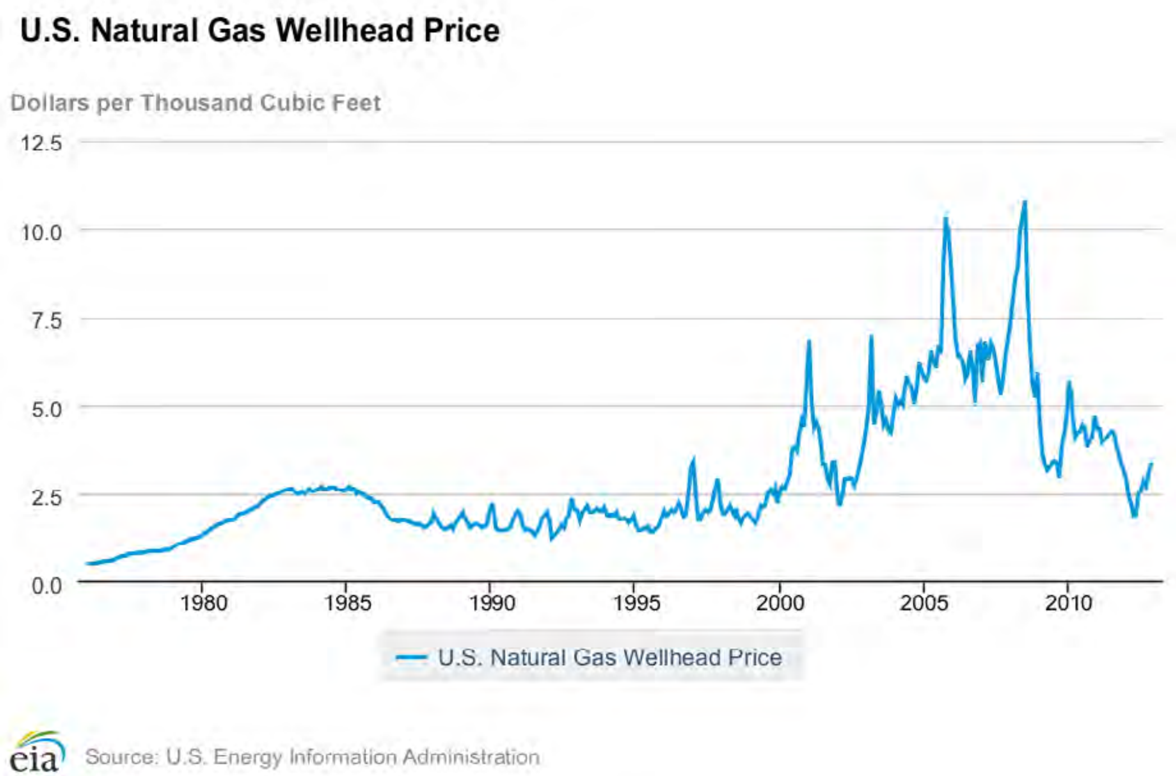
REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 9

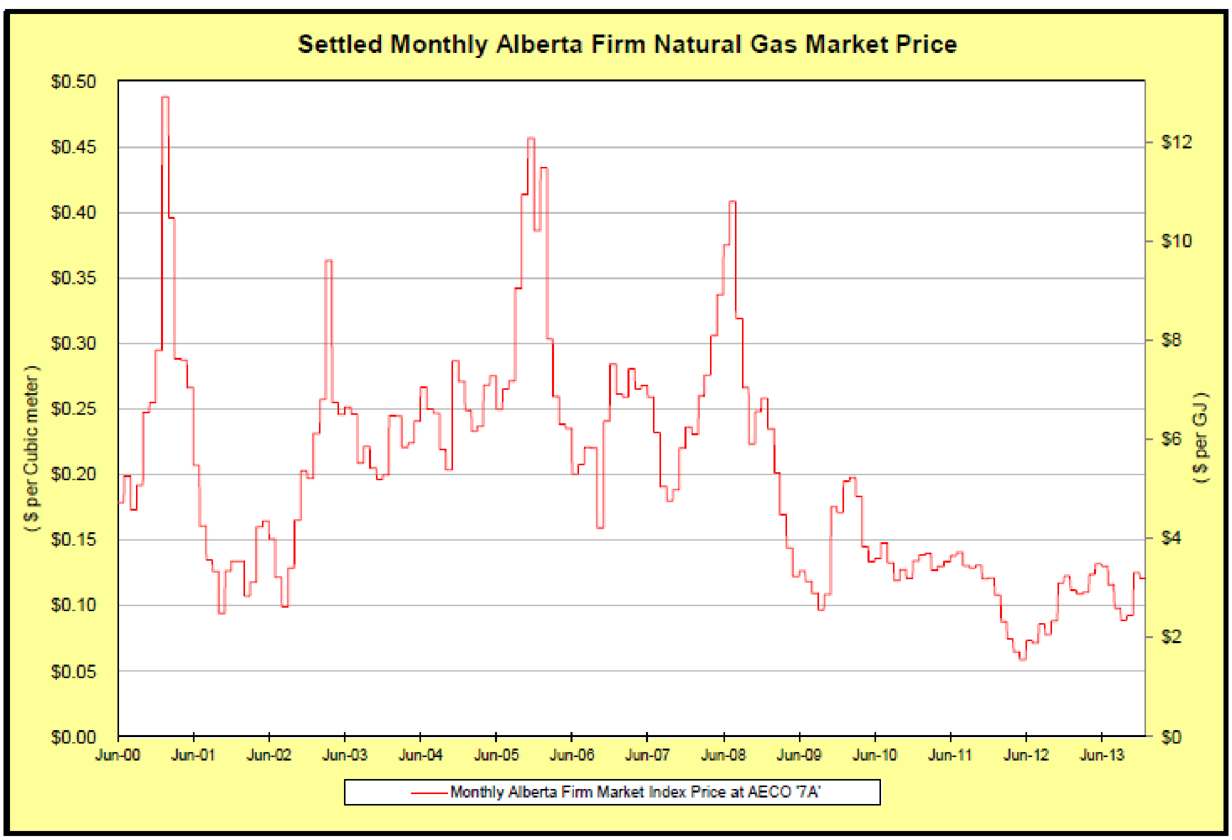
QUESTION:

Regarding the "Manitoba Delivered Fuel Costs" characteristic, provide all documentation supporting the "recent fuel-price volatility experienced by natural gas" in Manitoba. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

Natural gas is a commodity and as such its price fluctuates based on prevailing market conditions. The following graphs indicate the volatility of natural gas prices over the past years. The first graph is from the US Energy Information Administration and provides almost 40 years of historical US wellhead gas prices. The second graph of the Alberta Firm Natural Gas Market Price shows how the Alberta natural gas prices have tended to follow the historical US prices. Manitoba Hydro uses the forecast of Alberta natural gas prices for estimating natural gas-fired generation costs in Manitoba for planning purposes. Both graphs show much greater price volatility in the 2000-2010 periods than during other periods.


U.S. Natural Gas Wellhead Price
Dollars per Thousand Cubic Feet
12.5
10.0
7.5
5.0
2.5
0.0
1980
1985
1990
1995
2000
2005
2010
U.S. Natural Gas Wellhead Price
eia
Source: U.S. Energy Information Administration


Settled Monthly Alberta Firm Natural Gas Market Price
($ per Cubic meter)
$0.50
$0.45
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
($ per GJ)
$12
$10
$8
$6
$4
$2
$0
Jun-00
Jun-01
Jun-02
Jun-03
Jun-04
Jun-05
Jun-06
Jun-07
Jun-08
Jun-09
Jun-10
Jun-11
Jun-12
Jun-13
Monthly Alberta Firm Market Index Price at AECO '7A'

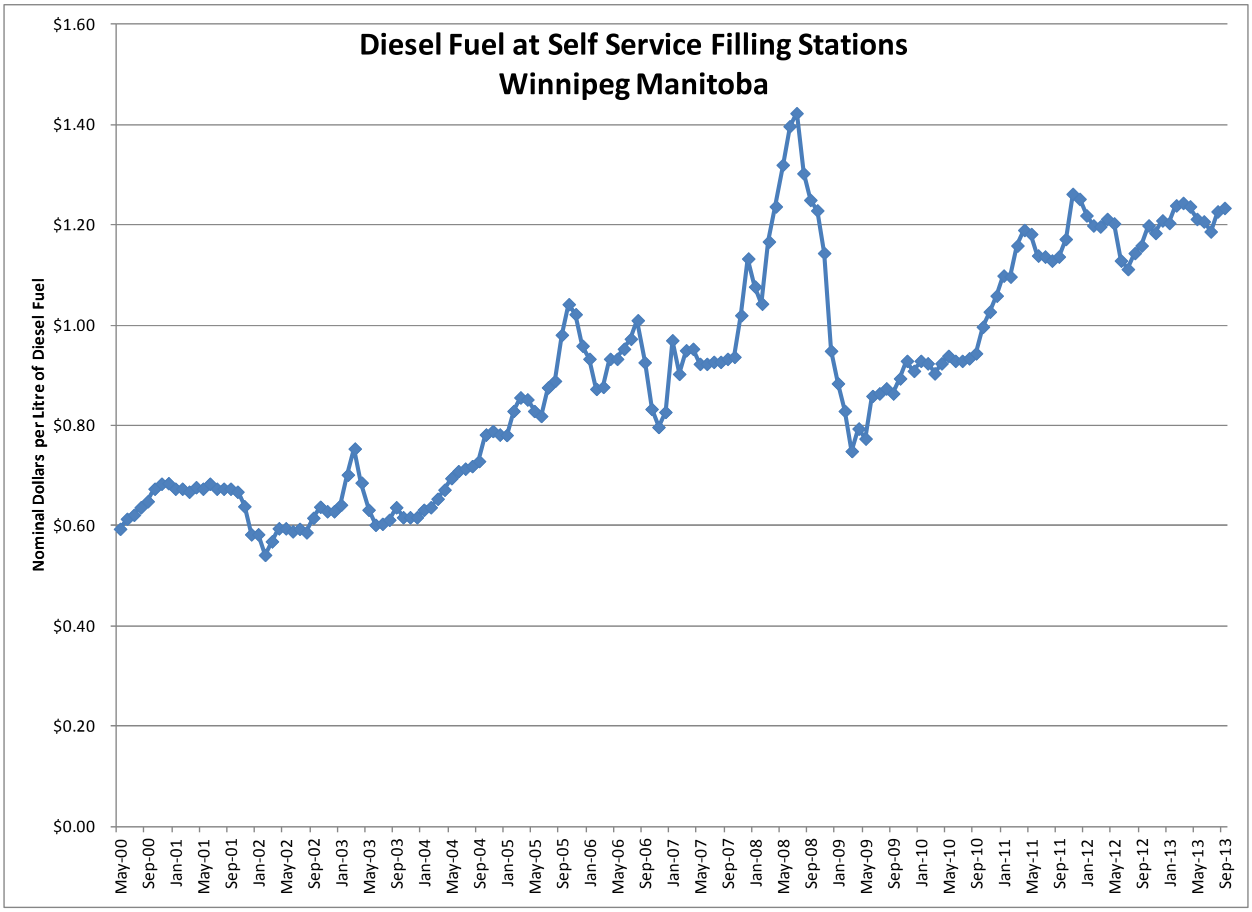
REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 9

QUESTION:

Regarding the "Manitoba Delivered Fuel Costs" characteristic, provide all documentation supporting the "rising transportation costs for fuel" in Manitoba. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

The cost of diesel fuel is set by prevailing market conditions and with the exception of the 2008 recession, over the past decade the cost of fuel has generally followed a steady upward trend over time. The following graph provides the historical cost of diesel fuel at Manitoba fuel stations over the past thirteen years. The information was obtained from the CANSIM database by Statistics Canada.

1 
Diesel Fuel at Self Service Filling Stations
Winnipeg Manitoba
Nominal Dollars per Litre of Diesel Fuel
$1.60
$1.40
$1.20
$1.00
$0.80
$0.60
$0.40
$0.20
$0.00
May-00
Sep-00
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REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 9-10

QUESTION:

Regarding the "Forecast U.S. Unit Cost" characteristic, provide all documentation supporting the specific designation of the three cost categories utilized, as well as an explanation of how the three categories were utilized in the screening process. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 11

QUESTION:

Provide the data represented in Figure 7.3 in tabular form in an excel spreadsheet.

RESPONSE:

The following are the levelized costs utilized within Figure 7.3 for the range of resource technologies. Please also see Manitoba Hydro's response to LCA/MH I-308 which provides levelized cost calculations for selected resource options.

	Resources Used in Figure 7.3 Ranges	2014$
Resource Technology	**Resource Option**	**$/MW.h**
DSM	2013 Power Smart	40
Hydro Low	Keeyask Generating Station	60
Hydro High	Bonald Generating Station	282
On-Shore Wind	Generic On-Shore Wind (65 MW)	84
Photovoltaic Low	Solar Photovoltaics - Single Axis	195
Photovoltaic High	Solar Photovoltaics - Dual Axis	201
Solar Thermal Low	Solar Parabolic Trough (No Thermal Storage)	145
Solar Thermal High	Solar Parabolic Trough (No Thermal Storage)	195
Enhanced Geothermal Low	Enhanced Geothermal System Generation	305
Enhanced Geothermal High	Enhanced Geothermal System Generation	454
SCGT Low	Heavy Duty Simple Cycle Gas Turbine	125
SCGT High	Aeroderivative Simple Cycle Gas Turbine	428
CCGT Low	Heavy Duty Combined Cycle Gas Turbine	75
CCGT High	Heavy Duty Combined Cycle Gas Turbine	97
Biomass Low	Wood Waste-Fired Generation (30MW)	133
Biomass High	Wood Waste-Fired Generation (15MW)	213

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 11

QUESTION:

Provide all calculations, assumptions, and supporting documentation for the levelized cost estimates provided in Figure 7.3. Where applicable, workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

Please see Manitoba Hydro's response to LCA/MH I-308.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 10-11

QUESTION:

Regarding Figure 7.3, provide all documentation, analysis, and other support for any differences between the Manitoba levelized costs and the U.S. levelized costs represented in Figure 7.2. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

The levelized cost values shown in Figure 7.2 are based on the US EIA's "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013" report. For a complete description of how these values are created please see the report at:

http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf

The Manitoba based estimates incorporate assumptions consistent with the resource potential within the provinces geographic location. Major differences between the US EIA's levelized cost values and the Manitoba based values are noted in the following areas along with a brief explanation:

Discount rates: The US EIA uses a discount rate of 6.6% while Manitoba Hydro uses a rate of 5.05%.

Dollar Year: The US EIA graph is presented in 2011$ while the Manitoba based graph is shown in 2014$.

Upper Hydro value – Manitoba Hydro maintains cost estimates for a range of potentially developable hydroelectric sites within Manitoba. The range in levelized cost reflects the difference between these sites; from the more economic sites at the lower end of the range to the less economic sites at the higher end of the range. The US EIA values show a range of costs for projects that are most likely to be constructed in the near future and as such have a much narrower and more favourable cost range.

Lower Photovoltaic value: Manitoba's geographic location results in a solar intensity level that is not as favorable as other jurisdictions mainly as a result of its northerly latitude. The impact is that the minimum levelized cost of electricity from solar photovoltaics in Manitoba is significantly higher than for other jurisdictions, especially for those in the southwestern United States.

Solar Thermal: The range of levelized costs from the US EIA contains a wide range of potential solar thermal technologies. Many of these technologies are still in their development and demonstration stage and as such have significantly higher costs of energy. The Manitoba based estimates contain only parabolic trough technology as it is viewed as the most commercially advanced, producing the least cost solar thermal energy. When comparing the two graphs the Manitoba based estimates are similar to the lower range of the US EIA based graph.

Enhanced Geothermal: High quality geothermal resources are specific to geographic locations, specifically those areas adjacent to volcanic or tectonically active areas. Manitoba does not contain any high quality geothermal heat sources comparable to those of the geothermal energy projects that could be potentially developed in geologically active areas which contribute to the US EIA cost estimates . As a result of Manitoba's lower quality resource, a deep, enhanced geothermal system would need to be utilized as a result of the low grade heat source. The impact is that because of the lower quality geothermal resource potential, the levelized cost of producing electricity is significantly higher than in other high quality sites that are available in other jurisdictions.

SCGT: The Manitoba based graph utilizes a range of capacity factors of 5% and 20% to represent the high and low ranges, while the US EIA based graph utilizes a capacity factor of 30%.

Biomass: The range of biomass based generation shown in the Manitoba based graph includes only agricultural waste and wood waste fuel sources. It does not include other potential source material that may be incorporated within the US EIA range. In addition, the Manitoba based graph includes relatively small generating units of 15 and 30 MW as they are viewed as being the most realistic for local development. The relative small size of these units are not large enough to take advantage of economies of scale of larger units included within the US EIA based range, and as such result in higher energy costs.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1; Page No.: 3, 11

QUESTION:

Regarding Table 7.1, explain why U.S. levelized costs were utilized for resource screening, rather than the Manitoba levelized costs represented in Figure 7.3

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 11

QUESTION:

Regarding Figure 7.3, are fuel collection and transportation costs factored into the levelized cost of biomass? If so, provide the portion of the levelized cost attributable to collection and transportation costs, as well as the workpapers supporting the calculation. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 11

QUESTION:

Regarding Figure 7.3, explain why biomass resources were screened out given the comparability in levelized cost to SCGT resources, which were not screened out.

RESPONSE:

Biomass generation is considered a baseload resource and was analyzed at 83% capacity factor. As a baseload resource, more similar to a CCGT resource, the biomass resource technology has a relatively high levelized cost of energy, due to a relatively high capital cost and high costs for collection and transportation of biomass fuel, and was screened out as a result. SCGT generation is used primarily for peaking purposes and was analyzed at 5% and 20% capacity factors. While a SCGT resource option can have a high levelized cost of energy, it represents a lower capital cost option for capacity requirements and as a result was included for further evaluation.

It should be noted that at a screening level, a cost comparison of different generating technologies on a levelized cost of energy basis is most valid when their mode of operation (i.e. baseload, intermediate or peaking) and capacity factors are similar.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 11

QUESTION:

Regarding the note to Figure 7.3 ("Values reflect losses to bring energy to market"), provide all loss assumptions and calculations utilized in the levelized cost figures, as well as any documentation supporting the loss assumptions. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.2.2; Page No.: 19

QUESTION:

Provide complete copies of the "Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations" and "The Climate Change and Emissions Reductions Act" as they currently apply Manitoba Hydro's resource planning.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.2.2; Page No.: 20

QUESTION:

Provide complete copy of the "Manitoba High-Level Radioactive Waste Act" as it currently applies to Manitoba Hydro's resource planning.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.2; Page No.: 24

QUESTION:

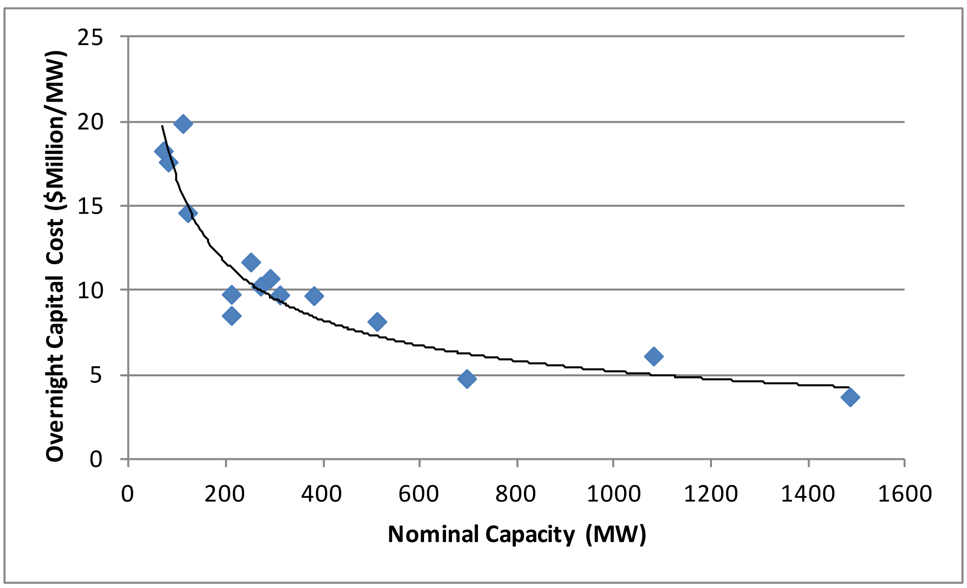
Provide all documentation and analysis supporting the statement that "Hydro-electric plants… can achieve economies of scale if large in size."

RESPONSE:

Appendix 7.2 provides preliminary cost estimates for several potential hydroelectric sites within the province. The nominal capacities of these sites range in size from 70 MW to 1485 MW. The overnight capital cost per megawatt of nominal capacity is provided in the table and figure below. As shown with the trend line in the figure, there is a strong relationship between the cost/MW of a hydro-electric plant located in northern Manitoba and its overall size.

As an example, to develop approximately 700 MW of additional system capacity, either Keeyask (695 MW) could be developed at an overnight cost of $3539 M, or First Rapids (210 MW), Kepuche (210 MW) and Red Rock (250 MW) for a combined capacity of 670 MW at an overnight cost of $6764 M could be developed. Constructing a single, larger site is less costly than developing multiple smaller sites.

Hydroelectric Sites	Nominal Capacity (MW)	Overnight Capital Cost ($Million/MW)
Manasan LH	70	18
Early Morning	80	18
Bonald	110	20
Granville	120	15
First Rapids	210	10
Kepuche	210	9
Red Rock	250	12
Manasan HH	270	10
Birchtree	290	11
Whitemud	310	10
Birthday	380	10
Bladder	510	8
Keeyask	695	5
Gillam Island	1080	6
Conawapa	1485	4



REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.2; Page No.: 24

QUESTION:

Provide all documentation and analysis supporting the statement that "Hydro-electric plants also tend to provide more significant economic stimulus to Manitoba than many other technologies."

RESPONSE:

Accounting for the benefits of developing different technologies is a complex evaluation taking into consideration a variety of factors and perspectives. Estimates of the net benefits from the direct construction and operating and maintenance employment generated by the different projects in the preferred and alternative development plans are incorporated into the multiple account benefit-cost assessment of development plans provided in Chapter 13 of the NFAT Business Case. This assessment demonstrates that the plans with hydro-electric generation development result in more direct construction employment and more employment overall. Hydro-electric generation projects also require concentrated employment in local regions where there are limited alternative employment opportunities and where, with proactive training and hiring policies, the greatest net economic benefits can be realized.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.2; Page No.: 27

QUESTION:

Regarding the statement that "[t]he small size of Notigi, combined with a higher levelized cost… results in Notigi receiving no further consideration in this submission," explain why project size is considered in the screening process. Provide any documentation or analysis supporting the decision to screen out hydro projects due to size. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.2; Page No.: 27

QUESTION:

Regarding the Notigi project, provide all documentation and analysis supporting the claim that the winter capacity would be reduced by "20MW or 16%." Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 31

QUESTION:

Explain why "[w]ind generation is assumed to have a zero winter peak capacity" when wind projects in MISO receive a 13.3% capacity credit, as discussed in Appendix 7.4.

RESPONSE:

As explained in Appendix 7.4 Capacity Value of Wind Resources at page 2:

> "MISO annually determines a wind resource capacity credit for wind generation located within the MISO market footprint. Note that the MISO market is a *summer peaking region* [Emphasis added] and the capacity value of wind to the MISO market is derived from the capacity contribution of the wind generation *during the summer peak load hours* [Emphasis added]."

As explained in Appendix 7.4 Capacity Value of Wind Resources at page 3:

> "For Manitoba Hydro, the analysis of capacity value of wind must consider the winter season as Manitoba Hydro has a winter peaking load. Manitoba Hydro has examined the performance of the existing wind generation fleet in Manitoba during the peak load hour of each month during the period from June 2007 to May 2013. In examining the data it was found that the minimum wind generation, during the peak load hour each month, was zero or near zero each least once each month.
>
> A further consideration for wind turbine operation in Manitoba is low temperature operation. At the present time, commercially available utility scale wind turbines are shut down at -30°C to avoid mechanical failures as a result of low temperature operation. As Manitoba Hydro is winter peaking, the very extreme cold temperatures

that cause low temperature wind turbine shut downs also tend to cause peak load conditions.

In consideration of the performance to date of wind generation during the peak monthly load conditions, and the operating requirement to shut down wind generators at -30°C, when the Manitoba load tends to be peaking, Manitoba Hydro has determined that the capacity value of wind generation within Manitoba to meeting the winter peak load is zero."

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 31

QUESTION:

Provide all documentation and analysis supporting the statement that "wind generators cannot be expected to operate reliably at temperatures below -30C."

RESPONSE:

This statement is a generic characterization of readily available, wind turbine, cold weather packages. Some examples of the designed operating ranges for low and high temperatures for four wind turbine manufacturers' cold weather versions of some of their models are included in the following table.

Manufacturer	Cold Weather Version	Designed Operating Range	
		Low Temp	High Temp
GE	1.5 or 2.5	-30°C	+40°C
Siemens	SWT-2.3	-25°C	+35°C
Vestas`	V90-3.0	-30°C	+40°C
Enercon	E-82	-25°C	+40°C

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 31

QUESTION:

Provide all documentation and analysis supporting the statement that "[w]ind turbine manufacturers have considered operations in extreme temperatures and have defined a cold climate as less than -20C for more than one hour in nine days per year."

RESPONSE:

A GL Garrad Hassan general characterization of “cold climate” is “less than -20C for more than one hour in nine days per year” and can be found on page 7 of the following public document:

http://www.gl-garradhassan.com/assets/downloads/Design_and_Installation_Challenges_in_Harsh_Environments.pdf

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 31

QUESTION:

Provide all documentation describing wind turbine "[m]anufacturers' cold weather packages" including cost, operation characteristics, etc.

RESPONSE:

Manitoba Hydro does not have the requested information as Manitoba Hydro does not own or operate wind farms. Detailed manufacturers' specifications are confidential and would have to be obtained directly from the manufacturers.

Please also see Manitoba Hydro's response to LCA/MH I-296.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

PREAMBLE: Provide the following information for the St. Leon and St. Joseph wind projects beginning with the commissioning of the projects through present:

QUESTION:

Hourly generation

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

PREAMBLE: Provide the following information for the St. Leon and St. Joseph wind projects beginning with the commissioning of the projects through present:

QUESTION:

Hourly available capacity

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

PREAMBLE: Provide the following information for the St. Leon and St. Joseph wind projects beginning with the commissioning of the projects through present:

QUESTION:

Hourly purchases by Manitoba Hydro (if different from generation)

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

PREAMBLE: Provide the following information for the St. Leon and St. Joseph wind projects beginning with the commissioning of the projects through present:

QUESTION:

Average losses by project

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

PREAMBLE: Provide the following information for the St. Leon and St. Joseph wind projects beginning with the commissioning of the projects through present:

QUESTION:

Records of all monthly payments made by Manitoba Hydro for energy or capacity under the power purchase agreements

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.3; Page No.: 6

QUESTION:

Provide copies of the power purchase agreements between Manitoba Hydro and the owners of the St. Leon and St. Joseph wind projects.

RESPONSE:[Confidential and Trade Secret]

As indicated in PUB/MH II-370b, Manitoba Hydro has provided copies of the St. Leon and St. Joseph wind power purchase agreements according to the commercially sensitive information process.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 32

QUESTION:

Regarding the statement that "industry forecasts to 2030 anticipate a 45% increase in energy output from wind turbines, assuming that material costs decrease by 10% in real terms from current levels," provide the referenced industry forecasts and any supporting documentation.

RESPONSE:

The projections for wind generation output and costs are sourced from the study titled “20% Wind Energy by 2030: Increasing Wind Energy’s Contribution to U.S. Electricity Supply”, DOE, May 2008. DOE/GO-102008-2578 Website link: http://www.nrel.gov/docs/fy08osti/41869.pdf.

The following table, extracted from this study, presents the expected performance and costs increments and highlights the values referenced in this information request.

Table 2-1. Areas of potential technology improvement

Technical Area	Potential Advances	Performance and Cost Increments (Best/Expected/Least Percentages)	
		Annual Energy Production	Turbine Capital Cost
Advanced Tower Concepts	• Taller towers in difficult locations • New materials and/or processes • Advanced structures/foundations • Self-erecting, initial, or for service	+11/+11/+11	+8/+12/+20
Advanced (Enlarged) Rotors	• Advanced materials • Improved structural-aero design • Active controls • Passive controls • Higher tip speed/lower acoustics	+35/+25/+10	-6/-3/+3
Reduced Energy Losses and Improved Availability	• Reduced blade soiling losses • Damage-tolerant sensors • Robust control systems • Prognostic maintenance	+7/+5/0	0/0/0
Drivetrain (Gearboxes and Generators and Power Electronics)	• Fewer gear stages or direct-drive • Medium/low speed generators • Distributed gearbox topologies • Permanent-magnet generators • Medium-voltage equipment • Advanced gear tooth profiles • New circuit topologies • New semiconductor devices • New materials (gallium arsenide [GaAs], SiC)	+8/+4/0	-11/-6/+1
Manufacturing and Learning Curve*	• Sustained, incremental design and process improvements • Large-scale manufacturing • Reduced design loads	0/0/0	-27/-13/-3
Totals		+61/+45/+21	-36/-10/+21

*The learning curve results from the NREL report (Cohen and Schweizer et al. 2008) are adjusted from 3.0 doublings in the reference to the 4.6 doublings in the 20% Wind Scenario.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 32-33

QUESTION:

Provide all documentation and analysis supporting the assumed average annual capacity factor of 40% for wind projects in southern Manitoba. Where possible please provide supporting information in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

Please see Manitoba Hydro's response to GAC/MH I-014 which provides a report by EPRI Solutions titled "Manitoba Hydro Wind Integration Sub-Hourly Operational Impacts Assessment". Section A4.3.1 Net Capacity Factor starting on page 128 of the report provides a discussion of net capacity factor.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.5; Page No.: 34

QUESTION:

Provide all capacity exchange agreements with U.S suppliers through which Manitoba Hydro has acquired winter capacity at no cost.

RESPONSE:

Refer to Manitoba Hydro’s response to LCA/MH I-423.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.3; Page No.: 39

QUESTION:

Regarding Table 7.6, provide all workpapers used to calculate the levelized cost for each technology. Workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

A workbook in Excel format has been included as an attachment in response to this information request.

http://www.hydro.mb.ca/projects/development_plan/bc_documents/lca/lca_308_attachment_1.xlsx

The workbook contains the breakdown of components used to calculate the levelized costs for 31 resource options referred to in either NFAT Business Case Chapter 7 Table 7.6 and/or Figure 7.3. The resource options included in the workbook are listed in the table below.

Additional information required to respond to this information request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

Sheet	Resource Option
1	Keeyask Generating Station
2	Conawapa Generating Station
3	Heavy Duty SCGT (5%CF)
4	Heavy Duty SCGT (20%CF)
5	Heavy Duty CCGT (35%CF)
6	Heavy Duty CCGT (70%CF)
7	Aeroderivative SCGT (5%CF)
8	Aeroderivative SCGT (20%CF)
9	Solar Photovoltaics - Fixed Tilt
10	Solar Photovoltaics - Single Axis
11	Solar Photovoltaics - Dual Axis Tracking
12	Solar Parabolic Trough (No Thermal Storage) - Low Capital
13	Solar Parabolic Trough (No Thermal Storage) - High Capital
14	Solar Parabolic Trough (6-hour Thermal Storage) - Low Capital
15	Solar Parabolic Trough (6-hour Thermal Storage) - High Capital
16	Generic On-Shore Wind (100 MW) - Low Capital, Stage I Trans.
17	Generic On-Shore Wind (100 MW) - Ref. Capital, Stage I Trans.
18	Generic On-Shore Wind (100 MW) - High Capital, Stage I Tans.
19	Generic On-Shore Wind (100 MW) - Low Capital, Stage II Trans.
20	Generic On-Shore Wind (100 MW) - Ref. Capital, Stage II Trans.
21	Generic On-Shore Wind (100 MW) - High Capital, Stage II Trans.
22	Generic On-Shore Wind (65 MW) - Ref. Capital, Stage I Trans.
23	Generic On-Shore Wind (65 MW) - Ref. Capital, Stage II Trans.
24	Generic In-lake Wind - Low Capital
25	Generic In-lake Wind - High Capital
26	DSM
27	Bonald Generating Station
28	Enhanced Geothermal System Generation - Low Capital
29	Enhanced Geothermal System Generation - High Capital
30	Wood Waste-Fired Generation (30 MW)
31	Wood Waste-Fired Generation (15 MW)

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.3; Page No.: 39

QUESTION:

Regarding Table 7.6, provide Manitoba Hydro's projected market prices through the study period.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 34

QUESTION:

Regarding Table 7.5, provide all workpapers used to calculate the levelized cost of energy. Workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

Please see Manitoba Hydro’s response to LCA/MH I-308.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; 7.3; Page No.: 34; 39

QUESTION:

Reconcile the levelized cost of wind energy cited in Table 7.5 ($82) and Table 7.6 ($86).

RESPONSE:

The levelized cost of wind energy shown in both Table 7.5 and Table 7.6 are based on the same information. The levelized cost of wind energy shown in Table 7.5 was inadvertently provided in 2012$ rather than the 2014$ indicated in the table.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2.4; Page No.: 39

QUESTION:

Regarding Table 7.5, explain why Manitoba Hydro assumed a 20-year asset life for wind projects when Manitoba Hydro has wind PPAs of 25 and 27 years for the St. Leon and St. Joseph wind farms, respectively.

RESPONSE:

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

The agreement to terms of 25 and 27 years are extensions of 5 and 7 years respectively beyond what is considered normal in the industry. Although the agreement details are confidential, Manitoba Hydro and the wind developers were able to agree to contract language that addressed the specific obligations, costs, and risks associated with the extended terms.

Please also see Manitoba Hydro's responses to GAC/MH I-010a and GAC/MH I-010b.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.0-7.3; Page No.: 1-39

QUESTION:

Please provide all Manitoba Hydro policies concerning using Requests for Proposals (RFPs) for merchant generation to meet resource needs and provide a list of all RFPs Manitoba Hydro has issued in the past ten years.

RESPONSE:

Manitoba Hydro has no RFP policies for acquiring merchant generation and at present is not actively soliciting for proposals. However in the future should there be a need, these will be dealt with on a case by case basis.

Manitoba Hydro issued RFP 025089 in March 2007 for the potential purchase of up to 300 MW of output from wind farms build within Manitoba by independent power producers.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 1.2; Page No.: 8

QUESTION:

Regarding Table Appendix 7.2-2, provide all workpapers used to calculate the levelized cost for each technology, with and without transmission. Workpapers should be provided in electronic spreadsheet format with formulas intact. All assumptions utilized in the calculations (i.e. capital cost, O&M cost, etc.) should be supported with associated documentation and analysis.

RESPONSE:

Please see Manitoba Hydro's response to LCA/MH I-308.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 1.2; Page No.: 8

QUESTION:

Regarding Table Appendix 7.2-2, provide all documentation and analysis supporting the assumptions regarding lifetime capacity factor.

RESPONSE:

Please see the attached tables which provide the referenced assumed capacity factor and the supporting source and/or the information related to the assumption.

RESOURCE OPTION	LIFETIME CAPACITY FACTOR	COMMENT or SOURCE	LINK
Solar Photovoltaics - Fixed Tilt	Approximately 20%	National Renewable Energy Laboratory (2012b). "PVWatts™ Grid Data Calculator (Version 2)". Retrieved 2013 02 28. From http://rredc.nrel.gov/solar/ calculators/PVWATTS/ version2/. For Grid Cell ID 0223343, CF = 5285 kWh / (3.08 kW X 8766 hours) = 19.6% or Approximately 20%.	http://rredc.nrel.gov/solar/calculators/PVWATTS/version2/inputv2.cgi?Cell_i_d_=0223343&Latitude=49.231&longitude=-101.171&State=North Dakota&Electric_r=7.369
Solar Photovoltaics - Single Axis Tracking	Approximately 26%	National Renewable Energy Laboratory (2012b). "PVWatts™ Grid Data Calculator (Version 2)". Retrieved 2013 02 28. From http://rredc.nrel.gov/solar/ calculators/PVWATTS/ version2/. For Grid Cell ID 0223343, CF = 6929 kWh / (3.08 kW X 8766 hours) = 25.7% or Approximately 26%.	http://rredc.nrel.gov/solar/calculators/PVWATTS/version2/inputv2.cgi?Cell_i_d_=0223343&Latitude=49.231&longitude=-101.171&State=North Dakota&Electric_r=7.369
Solar Photovoltaics - Dual Axis Tracking	Approximately 28%	National Renewable Energy Laboratory (2012b). "PVWatts™ Grid Data Calculator (Version 2)". Retrieved 2013 02 28. From http://rredc.nrel.gov/solar/ calculators/PVWATTS/ version2/. For Grid Cell ID 0223343, CF = 7464 kWh / (3.08 kW X 8766 hours) = 27.6% or Approximately 28%.	http://rredc.nrel.gov/solar/calculators/PVWATTS/version2/inputv2.cgi?Cell_i_d_=0223343&Latitude=49.231&longitude=-101.171&State=North Dakota&Electric_r=7.369

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Solar Parabolic Trough (No Thermal Storage)	Approximately 26%	Müller-Steinhagen, Hans (2008). "Solar Thermal Power Plants - On the Way to Commercial Market Introduction". 2008. Use the Solnova-1 and Nevada Solar One plants' capacity factors of 26% as a proxy value.	http://solarthermalworld.org/content/solar-thermal-power-plants-way-commercial-market-introduction-2008
Solar Parabolic Trough (6-hour Thermal Storage)	Approximately 40%	Müller-Steinhagen, Hans (2008). "Solar Thermal Power Plants - On the Way to Commercial Market Introduction". 2008. Use the Solana and Extresol-1 plants' capacity factors of 40% as a proxy value.	http://solarthermalworld.org/content/solar-thermal-power-plants-way-commercial-market-introduction-2008
Generic On-Shore Wind (100 MW)	40%	Please see Manitoba Hydro's response to GAC/MH I-0006 and GAC/MH I-014.	
Generic On-Shore Wind (65 MW)	40%	Please see Manitoba Hydro's response to GAC/MH I-0006 and GAC/MH I-014.	
Generic In-Lake Wind	43%	40% (MB on-shore) + [37% (EIA Offshore) - 34% (EIA On-shore)] = 43%	http://www.eia.gov/forecasts/aeo/electricity_generation.cfm
Enhanced Geothermal System Generation	90%	U.S. Department of Energy (2013). "2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010". December 2009.	http://www.eia.gov/oiaf/archive/aeo10/electricity_generation.html

2

RENEWABLE OPTIONS			
RESOURCE OPTION	**LIFETIME CAPACITY FACTOR**	**COMMENT or SOURCE**	**LINK**
Generic On-Shore Wind (100 MW)	40%	Please see Manitoba Hydro's response to GAC/MH I-0006.	
Generic On-Shore Wind (65 MW)	40%	Please see Manitoba Hydro's response to GAC/MH I-0006.	
Generic In-Lake Wind	43%	40% (MB on-shore) + [37% (EIA Offshore) - 34% (EIA On-shore)] = 43%	http://www.eia.gov/forecasts/aeo/electricity_generation.cfm
Enhanced Geothermal System Generation	90%	U.S. Department of Energy (2013). "2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010". December 2009.	http://www.eia.gov/oiaf/archive/aeo10/electricity_generation.html

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 1.2; Page No.: 8

QUESTION:

Regarding Table Appendix 7.2-2, provide all documentation and analysis supporting the assumptions regarding transmission cost.

RESPONSE:

Please see Manitoba Hydro's response to LCA/MH I-308.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 2.5; Page No.: 20

QUESTION:

Provide all documentation and analysis supporting the referenced estimates of solar project cost declines of 50% by 2020 and 75% by 2030.

RESPONSE:

The comment is based on a general trend characterization from IRENA Renewable Energy Technologies: Cost Analysis Series Solar Photovoltaics, June 2012:

http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-SOLAR_PV.pdf

Table 5.3 Installed PV System Cost Projections For Residential and Utility-Scale Systems, 2010 to 2030 provides the following utility-scale estimate values:

- 2010 - $3,600 to $4,000/kW
- 2020 - $1,800/kW
- 2030 - $1,060 to $1,380

The table provides a range of 45% to 50% reduction by 2020, and 62% to 74% reduction by 2030. Hence the sentence in Appendix 7.2 page 20 of 367 " In real terms, it is projected that Total Plant Costs will drop by over 50% by 2020 and 75% by 2030, making this option increasingly competitive in the future".

Please also see Manitoba Hydro's response to CAC_GAC/MH I-020a for additional context for solar PV costs.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 3.1; Page No.: 42-174

QUESTION:

For each hydroelectric resource option, provide all materials listed in the "References" section for each resource option. Provide an index listing the reference used for each assumption used in the data sheets. For any values in the resource data sheet that is the product of a calculation completed by or for Manitoba Hydro, provide the associated workpapers. Workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 3.2; Page No.: 175-285

QUESTION:

For each thermal resource option, provide all materials listed in the "References" section for each resource option. Provide an index listing the reference used for each assumption used in the data sheets. For any values in the resource data sheet that is the product of a calculation completed by or for Manitoba Hydro, provide the associated workpapers. Workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 7.2 Range of Resource Options; Section: 3.3; Page No.: 286-354

QUESTION:

For each emerging technology resource option, provide all materials listed in the "References" section for each resource option. Provide an index listing the reference used for each assumption used in the data sheets. For any values in the resource data sheet that is the product of a calculation completed by or for Manitoba Hydro, provide the associated workpapers. Workpapers should be provided in electronic spreadsheet format with formulas intact.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Section: Sections 1-6; Page No.: 1-78

QUESTION:

Provide all documents referenced in all footnotes of Appendix 7.1

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Section: 4.2.3; Page No.: 31

QUESTION:

Provide all documentation and analysis supporting the estimates of landfill gas potential and capacity factor.

RESPONSE:

In 2010 the Province of Manitoba announced a landfill gas capture program to enable three of Manitoba's largest landfills to "make significant reductions to the amount of greenhouse gas emissions they release". These three landfills are as follows:

- Brady Road Resource Management Facility owned and operated by the City of Winnipeg
- Eastview Landfill Site owned and operated by the City of Brandon
- BFI Canada Prairie Green Landfill privately owned and operated by BFI Canada Inc.

The basis of the estimate on Page 31 of Section 4.2.3 in Appendix 7.1 was landfill gas volume estimates in cubic feet per minute (cfm) derived from studies undertaken by the City of Brandon and the City of Winnipeg. A 2G CENERGY Avus 2000 BG (CHP type) reciprocating engine was used to estimate the electrical capacity. Average methane flows of 6.25 and 6.88 cfm per well have been recorded at Eastview in Brandon and Brady Road in Winnipeg respectively. With well depths varying between 6 and 18m, an initial 49 well development at Eastview in Brandon and 136 well development at Brady Road in Winnipeg, with 6 and 15 wells, respectively, added per year over the 20 year life of the project, are required to maintain steady gas flows.

The 8 MW output from landfill gas discussed in Appendix 7.1 is a rounded estimate based on the following annual average methane gas flow, electrical and thermal energy potential and capacity estimates from information provided by the City of Brandon and the City of Winnipeg.

Landfill Site	**Gas Flow CH_4 Volume (cfm)**	**Energy (electrical) GWh/year**	**Energy (thermal) GWh/year**	**Capacity (electrical) MW**
Eastview Brandon	304	17.5	18.4	2.0
Brady Rd Winnipeg	930	56.2	59.2	6.4
TOTAL	1234	73.7	77.6	8.4

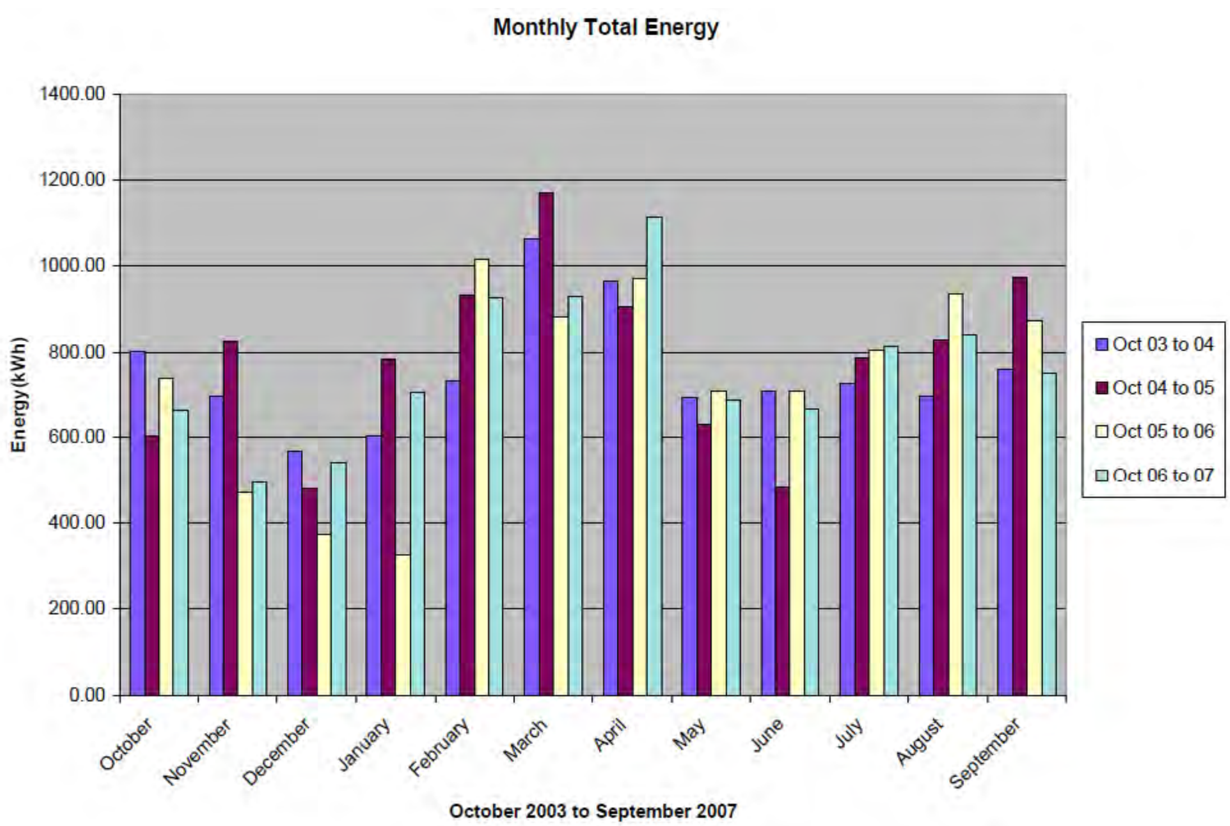
REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Section: 4.4.3; Page No.: 48

QUESTION:

Provide all monitoring data supporting the reported 8% capacity factor of the Red River College solar project, including hourly generation and hourly available capacity.

RESPONSE:

Manitoba Hydro does not own or have the monitoring data from the solar project at Red River College. The University of Manitoba provided the following summary for the October 2003 to September 2007 time period for the 12.7 $kW_{(AC)}$ Red River College, Princess Street Campus, solar PV project (average 742 kWh per month or 8% capacity factor).



REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Provide a description of the process whereby the specific development plans were formulated, including all factors utilized regarding timing and selection of resource types.

RESPONSE:

As described in Chapter 4 of the NFAT Business Case, and as shown in Appendix 4.2, a number of factors contribute to the determination of the annual supply demand surplus or deficit into the future. The year that deficits begin in either dependable energy or winter peak capacity is the year that new resources are required. All development plans are initially driven by the need for additional capacity and dependable energy resources. For the development plans presented in Chapter 8, resources are needed in 2022/23 to meet dependable energy requirements and in 2025/26 to meet peak capacity requirements. The development plans were prepared to ensure that energy and capacity demand is met over the entire 35 year planning period.

As described in Chapter 8, once the initial timing of the need for new resources has been determined, development plans are identified using a number of combinations of new generation options and export opportunities available to Manitoba Hydro. The variability in costs and characteristics and the earliest availability of potential new resources allow for a variety of development plans which satisfy Manitoba Hydro's planning criteria and provide sufficient dependable energy and winter peak capacity to meet the projected requirements for the detailed 35 year study period. Further to this requirement, Manitoba Hydro formulates development plans which incorporate opportunities such as building new transmission interconnections, pursuing other renewable resources or pursuing export sales for the overall benefit of Manitoba. From an analytical perspective, combinations of options provide feasible development plans which allow for comparative analysis on an incremental basis. For example, as described in Chapter 9, pages 2 and 3, Manitoba Hydro does not have a “do nothing” option. In the case of Manitoba Hydro’s analysis, the closest representation of a “do nothing” option is the least capital cost investment alternative which is Plan 1, the optimized All Gas plan. Each of the 15 development plans is described in Chapter 8 Section 8.2.3. Each plan satisfies Manitoba Hydro’s planning criteria and meets the requirements for dependable energy and winter capacity as required. In addition, the opportunity to pursue a new interconnection together with the export sales which facilitates a new interconnection is described. Additional information is provided where applicable, such as on page 12 of Chapter 8 where the K19/Gas31/750MW plan is described as allowing “for the comparison of the option of building natural gas-fired generation as an alternative to building Conawapa G.S. starting in 2031/32”.

When considering the combinations of resource options in formulating development plans for a 35 year period the characteristics of the different resource options are considered. Chapter 7 outlines the key technical, environmental, social and policy, and economic characteristics of the different resource options that were considered for inclusion in the formulation of development plans as a result of a screening process. Appendix 9.3 provides the documentation of the assumptions used in formulating the plans and conducting the comparative analysis. For example, it is recognized that natural gas-fired plants have relatively low capital costs, can generally be sized to match closely anticipated increases in Manitoba load, and can be brought into service with relatively short lead times. Natural gas-fired plants also tend to have higher operating costs and result in potential exposure to fuel price volatility. Conversely, hydro-electric plants are long-lead time and long-life resources which tend to be built in large increments and therefore have large upfront capital investment costs, but have very low operating costs and provide benefits from export opportunities. Wind generation options also have upfront capital investment costs and low operating costs. Wind generation can generally be sized to match closely anticipated energy increases in Manitoba load and can be brought into service with relatively short lead times. As an intermittent resource, wind generation can be relied upon in Manitoba Hydro’s system to provide annual dependable energy but requires additional capacity resources to fulfill capacity requirements. Manitoba Hydro recognizes and takes into consideration the different risk profiles and opportunities of the different types of generation options. Having development plans with different combinations of these resource options enables the comparative analysis found in the NFAT Business Case.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Explain why none of the evaluated development plans included both wind development and new US interconnection capability

RESPONSE:

Development plans evaluated in the NFAT filing which include new US interconnection capability and associated new export sales are contingent on the construction of new hydroelectric generation in Manitoba. Manitoba Hydro did not contemplate the inclusion of new US interconnections in development plans that did not include new export sales to customers who would invest in the new interconnection and/or would be responsible for pursuing regulatory approval and construction of the US portion of a new interconnection.

In addition, in the analysis of development plans that included new wind generation, the overall economics of wind generation in the early years did not support the development of significant amounts of wind generation within Manitoba.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

If Manitoba Hydro is able to secure zero cost winter capacity through capacity exchange agreements (See Chapter 7, Section 7.2.5), explain why this option was not incorporated into development plans with wind capacity.

RESPONSE:

Under Seasonal Diversity Agreements Manitoba Hydro receives winter capacity in exchange for providing summer capacity with no capacity premiums being paid. The 2012 NFAT Reference Wind/Gas development plan, located in Appendix 4.2 pages 56 and 57, includes Seasonal Diversity Agreements with Northern States Power which provides 350 MW of winter capacity and Great River Energy which provides 200 MW of winter capacity both of which expire in April, 2025.

Manitoba Hydro did not include any additional contracts or assume that any specific contracts would be renewed after their expiry date in any of the development plans included in the NFAT 2012 Reference Business Case analysis. For the 2013 Update, the GRE Diversity was extended by five years to reflect the updated status of negotiations under the signed term sheet. For planning purposes contracts are not included in the Supply and Demand Tables unless they are signed or are in negotiations related to a signed Term Sheet as Manitoba Hydro has no indication whether counterparties will or will not extend these arrangements.

Extending the Seasonal Diversity Agreements is expected to be of benefit to all of the development plans, although it is not known which plans would benefit more on a relative basis as no specific studies have been completed.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Explain why none of the evaluated development plans included both wind development supported by combined cycle capacity.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Please explain the "process that was gone through to try and reflect when the natural gas would be required to provide the capacity backup for the wind." Provide all analyses and documentation supporting this process.

RESPONSE:

New natural gas-fired resources are included in development plans to provide the capacity backup for wind as a low capital cost resource with expected low dispatch as capacity resources over the average of all flow cases, which results in Simple Cycle Gas Turbines (SCGTs) being selected for this purpose.

As wind generation is not considered to have winter peaking capacity within the Manitoba Hydro system, and as winter peak capacity is used to determine the need for new capacity resources, in a development plan such as the Wind/Gas Plan new natural gas-fired generation is required to meet any capacity deficits during the planning study period. In the Wind/Gas Plan, capacity resources are not required until 2025/26, which is when the first new SCGTs are included in the plan. The full winter peak capacity of the new SCGT resources is included in the system surplus total starting in that in service year, and the next new SCGT's are added by the same method as required when winter peak capacity deficits occur until the end of the 35 year detailed study period. The planned in-service dates for new SCGTs are shown in the NFAT Business Case Chapter 8 Table 8.1.

SCGTs are also added in the Wind/C26 Plan subsequent to Conawapa G.S., included as a low-capital cost resource to meet energy and capacity needs with a starting date of 2036/37.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Provide all documentation and analysis related to Manitoba Hydro's evaluation of a "gas Keeyask" development plan, as referenced in the transcript.

RESPONSE:

The Gas/Keeyask development plan included in the Pathway 1 discussion in ***Chapter 14 – Conclusions*** in the NFAT submission was not available at the time of filing.

Subsequent to filing of the NFAT submission, for general comparison, Manitoba Hydro has completed an economic analysis of this development plan, which includes the following resources:

Development Plan	New Resources and Dates				New US Interconnection Capability
	Hydro	SCGT	CCGT	Wind	
Gas22/K28	2028 - Keeyask	2022 - 1 x 7FA 2025 - 1 x 7FA	2034 - 1 x 7 FA 2038 - 1 x 7 FA 2041 - 1 x 7 FA 2045 - 1 x 7 FA	None	None

The results of the economic analysis of this development plan incremental to the All Gas plan for the reference scenario are provided in the following table:

Development Plan	Incremental NPV millions of 2014 Dollars @ 5.05% Discount Rate	
	1 All Gas	Gas22/K28
1 All Gas Lowest Capital Investment Development Plan	-	-
Gas22/K28	Gas22/K28 minus All Gas	
	$709	-
2 K22/Gas	K22/Gas minus All Gas	K22/Gas minus Gas22/K28
	$887	$178

The table shows that under reference scenario, the incremental NPV for the K22/Gas plan is $178 M higher than that for the Gas22/K28 plan.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3-22

QUESTION:

Provide all wind cost data from EPRI and "other industry sources" referenced in the transcript.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1; Page No.: 3-6

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce the graphs in Figures 12.1, 12.2, 12.3 and 12.4.

RESPONSE:

The data used to generate Figures 12.1 and 12.2 of Chapter 12 is provided in spreadsheet format as an attachment.

www.hydro.mb.ca/projects/development_plan/bc_documents/lca/la_capra_338_attachment_1.xlsx

Figure 12.3 is based on tables named "System Firm Energy Demand and Dependable Resources (GWh) @ generation, NFAT 2013 Update, No New Resources". These tables are located in ***Appendix 4.2 Manitoba Hydro Supply and Demand Tables***, Section 5, pages 122-123. The numbers used in the chart are found on line 11 System Surplus/(Deficit).

Figure 12.4 is based on tables named "System Firm Winter Peak Demand and Capacity Resources (MW) @ generation, NFAT 2013 update, No New Resources". These tables are found in ***Appendix 4.2 Manitoba Hydro Supply and Demand Tables***, Section 5, pages 120-121. The numbers used in the chart are found on line 11 called System Surplus/(Deficit).

Please refer to Manitoba Hydro's response to LCA/MH I-246 which has been filed in confidence with the Public Utilities Board and provides more detailed information for the "2013 NFAT Update, No New Resources" Supply and Demand tables required to prepare Figures 12.3 and 12.4 in Chapter 12.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1.3; Page No.: 7

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce Tables 12.1 and 12.2

RESPONSE:

Table 12.1 numbers are taken from a table named "System Firm Winter Peak Demand and Capacity Resources (MW) @ generation, NFAT 2013 Update, No New Resources". This table is located in ***Appendix 4.2 Manitoba Hydro Supply and Demand Tables***, Section 5, page 120. The information in Appendix 4.2 corresponds to the information in Table 12.1 as follows:

Table 12.1	Corresponding line in Appendix 4.2, page 120
Total Base Supply	line 5, Total Base Supply Power Resources
Total Peak Demand	line 9, Total Peak Demand
Reserves	line 10, Reserves
System Surplus (Deficit)	line 11, System Surplus/(Deficit)

Table 12.2 numbers are taken from a table named "System Firm Energy Demand and Dependable Resources (GWh) @ generation, NFAT 2013 Update, No New Resources". This table is located in ***Appendix 4.2 Manitoba Hydro Supply and Demand Tables***, Section 5, page 122. The information in Appendix 4.2 corresponds to the information in Table 12.2 as follows:

Table 12.2	Corresponding line in Appendix 4.2, page 122
Total Base Supply	line 6, Total Base Supply Power Resources
Total Energy Demand	line 10 Total Energy Demand
System Surplus (Deficit)	line 11, System Surplus/(Deficit)

Please refer to Manitoba Hydro's response to LCA/MH I-246 which has been filed in confidence with the Public Utilities Board and provides more detailed information for the "2013 NFAT Update, No New Resources" Supply and Demand tables required to prepare Tables 12.1 and 12.2 in Chapter 12.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.4; Page No.: 15

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce Tables 12.6 and 12.7

RESPONSE:

Please refer to excel spreadsheet link

www.hydro.mb.ca/projects/development_plan/bc_documents/lca/lca_341_attachment_1.xlsx

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.4.1; Page No.: 19; 21

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce the graphs in Figures 12.5, 12.6.

RESPONSE:

Please see the attached spreadsheet provided for the information used to produce Figures 12.5 and 12.6.

2013 Update/DSM NFAT Plan Results

Millions of 2014 Present Value $ @ 5.4% Discount Rate

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate													
	1	2	3	4	5	6	7	8	9	10	11	12	13 WPS (Sale & Inv)	14
1 All Gas														
Lowest Capital Investment Development Plan	-													
2 K30/Gas 4x DSM	2 -1													
	$2,365													
3 K24/Gas 1.5x DSM	3 -1	3 -2												
	$1,034	($1,331)												
4 K23/Gas	4 -1	4 -2	4 -3											
	$728	($1,637)	($306)											
5 K19/Gas34/250MW 4x DSM	5 -1	5 -2	5 -3	5 -4										
MP Sale	$3,252	$887	$2,218	$2,524										
6 K19/Gas30/250MW 1.5x DSM	6 -1	6 -2	6 -3	6 -4	6 -5									
MP Sale	$1,463	($902)	$429	$735	($1,789)									
7 K19/Gas30/250MW	7 -1	7 -2	7 -3	7 -4	7 -5	7 -6								
MP Sale	$1,133	($1,232)	$99	$405	($2,119)	($330)								
8 K19/C33/750MW	8 -1	8 -2	8 -3	8 -4	8 -5	8 -6	8 -7							
MP Sale	$1,204	($1,161)	$170	$476	($2,048)	($259)	$71							
9 K19/C30/750MW 4x DSM	9 -1	9 -2	9 -3	9 -4	9 -5	9 -6	9 -7	9 -8						
MP Sale, WPS Sale & Inv	$3,448	$1,083	$2,414	$2,720	$196	$1,985	$2,315	$2,244						
10 K19/C26/750MW 4x DSM	10 -1	10 -2	10 -3	10 -4	10 -5	10 -6	10 -7	10 -8	10 -9					
MP Sale, WPS Sale & Inv	$3,437	$1,072	$2,403	$2,709	$185	$1,974	$2,304	$2,233	($11)					
11 K19/C26/750MW 1.5x DSM	11 -1	11 -2	11 -3	11 -4	11 -5	11 -6	11 -7	11 -8	11 -9	11 -10				
MP Sale, WPS Sale & Inv	$1,805	($560)	$771	$1,077	($1,447)	$342	$672	$601	($1,643)	($1,632)				
12 K19/C26/750MW	12 -1	12 -2	12 -3	12 -4	12 -5	12 -6	12 -7	12 -8	12 -9	12 -10	12 -11			
MP Sale, WPS Sale & Inv	$1,462	($903)	$428	$734	($1,790)	($1)	$329	$258	($1,986)	($1,975)	($343)			

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate			
	1 - All Gas	2 - K23/Gas	4 - K19/Gas30/250MW	12 - K19/C33/750MW
1 All Gas				
Lowest Capital Investment Development Plan	-			
2 K23/Gas	2 -1			
	$728			
4 K19/Gas30/250MW	4 -1	4 -2		
MP Sale	$1,133	$405		
12 K19/C33/750MW	12 -1	12 -2	12 -4	
MP Sale	$1,204	$476	$71	
14 K19/C26/750MW	14 -1	14 -2	14 -4	14 -12
MP Sale, WPS Sale & Inv Preferred Development Plan	$1,462	$734	$329	$258

Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate	
	2 - K24/Gas 1.5x DSM	4 - K19/Gas30/250MW 1.5x DSM
2 K24/Gas 1.5x DSM		
	-	
4 K19/Gas30/250MW 1.5x DSM	4 -2	
MP Sale	$429	
14 K19/C26/750MW 1.5x DSM	14 -2	14 -4
MP Sale, WPS Sale & Inv Preferred Development Plan	$771	$342

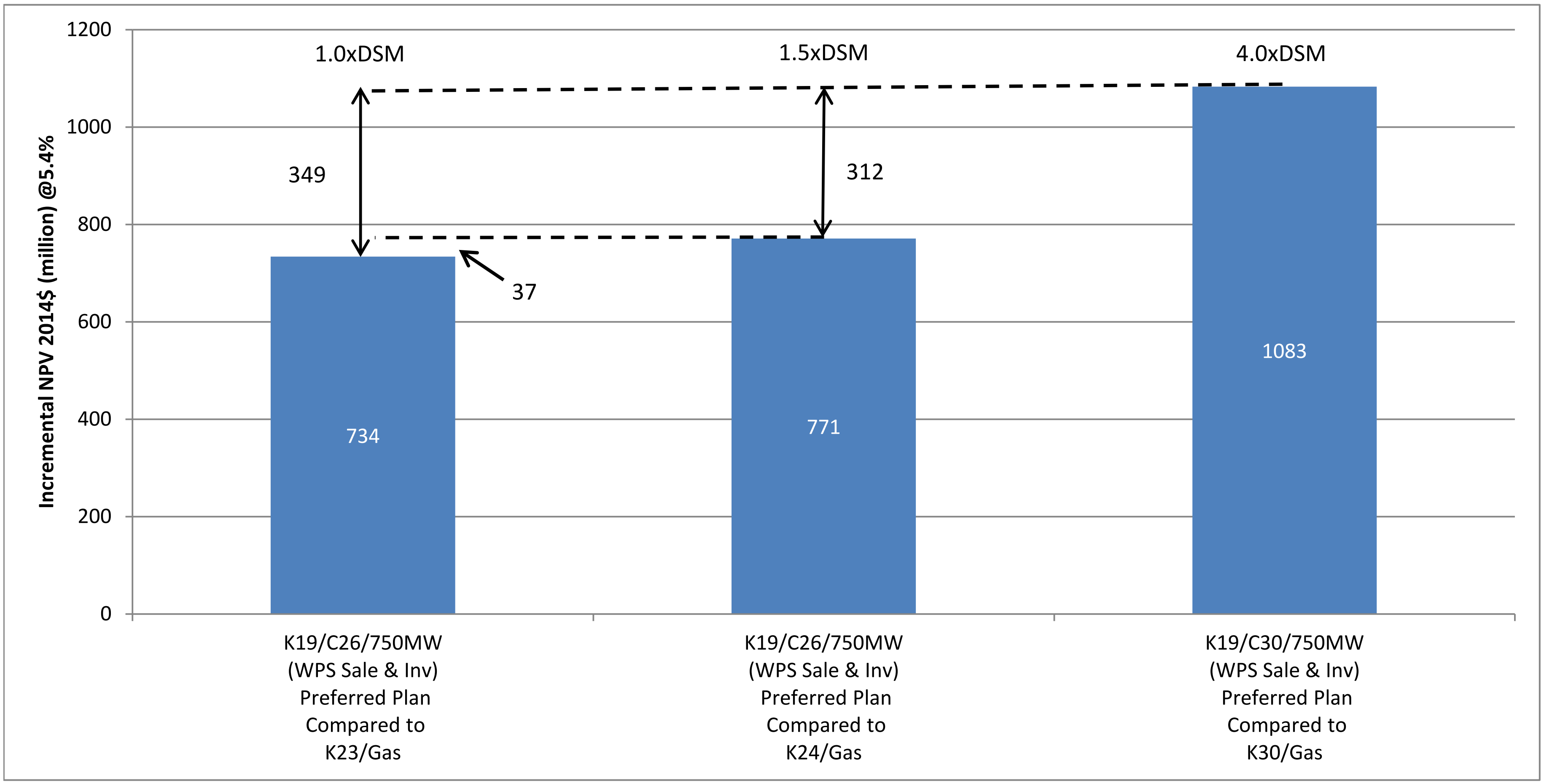
Development Plan	Incremental NPV, millions of 2014 Dollars @ 5.40% Discount Rate		
	2 - K30/Gas 4x DSM	4 - K19/Gas34/250MW 4x DSM	14a - K19/C30/750MW 4x DSM WPS Sale & Inv
2 K30/Gas 4x DSM	-		
4 K19/Gas34/250MW 4x DSM	4 -2		
MP Sale	$887		
14a K19/C30/750MW 4x DSM	14a -2	14a -4	
MP Sale, WPS Sale & Inv Conawapa G.S. Deferred by 4x DSM	$1,083	$196	
14 K19/C26/750MW 4x DSM	14 -2	14 -4	14- 14a
MP Sale, WPS Sale & Inv Preferred Development Plan	$1,072	$185	($11)

All cells are referenced from 'All Plans-basis for Tables' tab
All values are given in millions of 2014 Dollars @ 5.40% Discount Rate

	1.0xDSM	1.5xDSM	4.0xDSM		
	Figure 12.5				
description	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K23/Gas	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K24/Gas	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K30/Gas	K19/C30/750MW (WPS Sale & Inv) Preferred Plan Compared to K30/Gas	
incremental	734	771	1072	1083	These are the incremental values from the stair tables
		37	338	349	312 value of increment between K19/C30/750MW(WPS Sale & Inv) Preferred Plan Compared to K30/Gas and K19/C26/750MW(WPS Sale & Inv) Preferred Plan Compared to K24/Gas

	Figure 12.6				
description	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas30/250MW	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas30/250MW	K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas34/250MW	K19/C30/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas34/250MW	
incremental	329	342	185	196	These are the incremental values from the stair tables
		13	-144	146	

Descriptions	Truncated for charts
K19/C26/750MW	K19/C26/750MW(WPS Sale & Inv) Preferred Plan
K19/C26/750MW 1.5x DSM	K19/C26/750MW(WPS Sale & Inv) Preferred Plan
K19/C26/750MW 4x DSM	K19/C26/750MW(WPS Sale & Inv) Preferred Plan
K23/Gas	K23/Gas
K24/Gas 1.5x DSM	K24/Gas
K30/Gas 4x DSM	K30/Gas
K19/Gas30/250MW	K19/Gas30/250MW
K19/Gas30/250MW 1.5x DSM	K19/Gas30/250MW
K19/Gas34/250MW 4x DSM	K19/Gas34/250MW
K19/C30/750MW 4x DSM	K19/C30/750MW(WPS Sale & Inv) Preferred Plan



1200
1000
800
600
400
200
0
Incremental NPV 2014$ (million) @5.4%
1.0xDSM
1.5xDSM
4.0xDSM
349
312
37
734
771
1083
K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K23/Gas
K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K24/Gas
K19/C30/750MW (WPS Sale & Inv) Preferred Plan Compared to K30/Gas

Fig 12.5

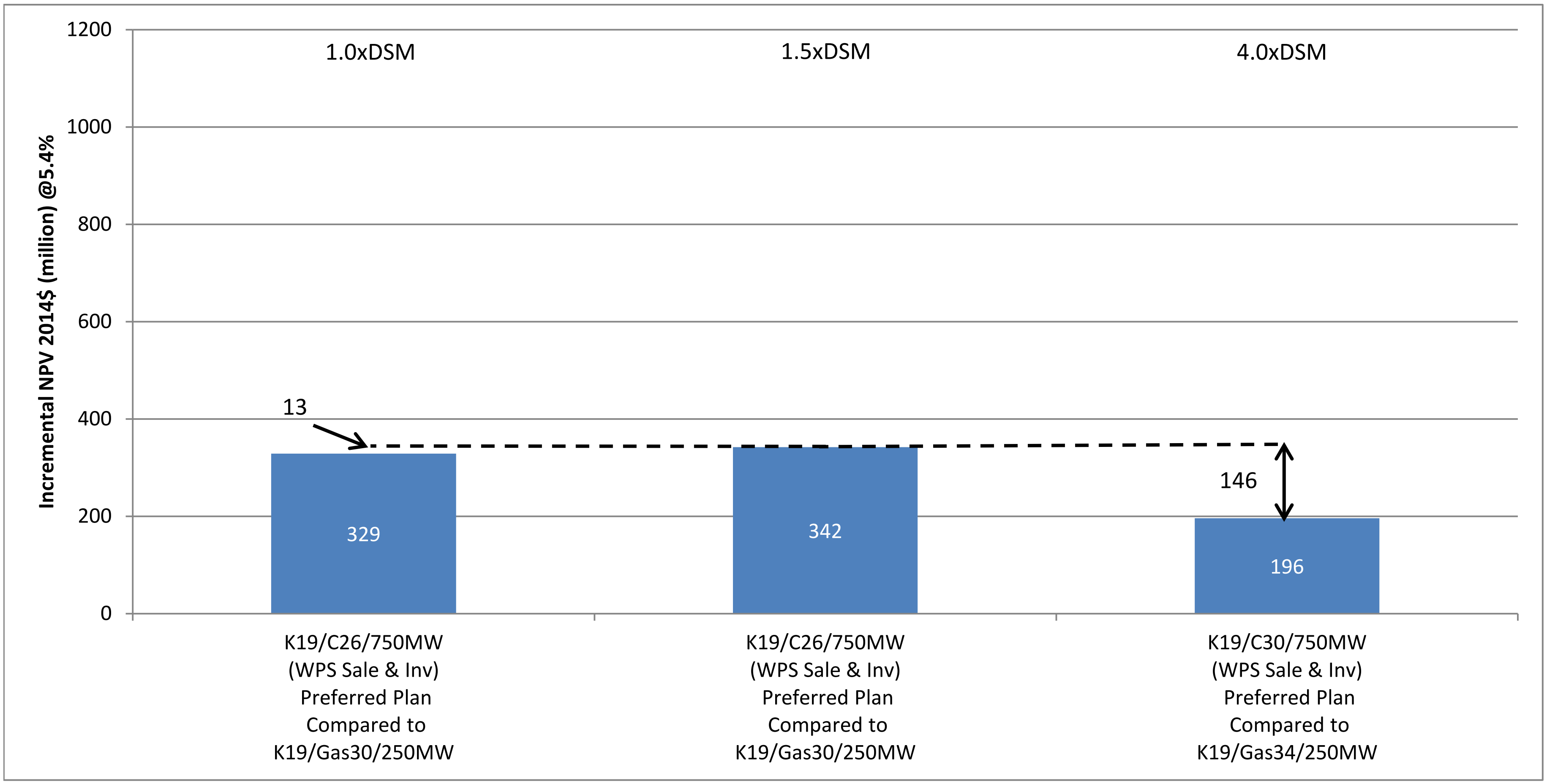

1200
1000
800
600
400
200
0
Incremental NPV 2014$ (million) @5.4%
1.0xDSM
1.5xDSM
4.0xDSM
13
146
329
342
196
K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas30/250MW
K19/C26/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas30/250MW
K19/C30/750MW (WPS Sale & Inv) Preferred Plan Compared to K19/Gas34/250MW

Fig 12.6

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.4.1; Page No.: 7

QUESTION:

In section 12.1.4 of Chapter 12 the report states that "The 2013 Electricity Export Price Forecast was prepared using the consensus forecasting methodology described in Appendix 9.3 – Economic Evaluation Documentation." Please provide, in electronic format with all formulae intact, all file or files used to produce the 2013 Electricity Export Price Forecast.

RESPONSE:

Manitoba Hydro's export market price worksheets and related supporting documents are considered Commercially Sensitive Information pursuant to the Terms of Reference – Needs For and Alternatives to (NFAT) Review. Copies of the requested files have already been shared with the Independent Expert Consultants (IEC).

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1.5; Page No.: 7

QUESTION:

Please list all reasons the earliest in-service date for Conawapa was changed from 2025/26 to 2026/27 in the 2013 update forecast.

RESPONSE:

The earliest in-service date for Conawapa was changed from 2025/26 to 2026/27 in the 2013 update due to two factors:

1) The 2013 Manitoba load forecast was lower than the 2012 forecast. When this was incorporated into the capacity/energy calculations and tables, the required ISD for Conawapa in the Preferred Plan deferred from 2025 to 2026

2) Updated expected timelines associated with pre-construction activities such as environmental assessment, regulatory review and licensing, agreements management, and community consultations were becoming extended making a 2025 ISD difficult to achieve.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1; Page No.: 1

QUESTION:

Is the Great River Energy Diversity Exchange agreement contract term still planned to end in 2030/31? If not, what is the new expected contract term?

RESPONSE:

The Great River Energy Diversity Exchange has been signed and has received all necessary approvals. The term for the agreement ends April 30, 2030.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 23

QUESTION:

Please refer to Table 9.7, which shows that development plan 15 provides $67 million in incremental benefit compared to development plan 12. In Manitoba Hydro's view, is the $67 million a significant difference between the plans or small enough to result in indifference between the plans and why?

RESPONSE:

Given the relative magnitude of the costs and revenues associated with development plan 15, a difference in incremental NPV of well over $100 million would be required to determine conclusively under the reference scenario that one plan is more attractive than another plan. From an economic perspective, consideration must also be given to the overall risk profile to identify any tradeoffs between upside potential and downside risk as described in Chapter 10 and shown in Figure 10.16. In terms of the overall business case conclusions, in addition to the economics, the financial, multiple accounts and optionality perspectives are important to the overall business case conclusions provided in Chapter 14.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.4.1; Page No.: 17

QUESTION:

Please refer to Chapter 12, page 17, which states that "deferring Conawapa G.S. from 2026/27 to 2030/31, shows a net benefit of $11 million…an amount which is small enough to result in indifference between the plans." At what level of net benefit would the difference in NPV be significant enough to favor one plan over the other?

RESPONSE:

The description of incremental NPVs between development plans as indifferent, significant or conclusive is dependent on the characteristics of the development plans (e.g. size of investment, upside and downside risk and tradeoffs) and whether the plans being compared have similar or different characteristics. For example, an amount may be considered significant in one comparison where the size of investment is low, in relative terms, where it may be considered as indifferent in plans where the level of investment is high, in relative terms.

Indifference would be defined as the lowest range and in many situations could reach incremental NPV values in excess of $50 million. Significant, would be defined as the middle range and in many situations could start at an incremental NPV of less than $50 million and be in excess of $100 million. Conclusive would be defined as the highest range and in most situations the incremental NPV would need to be at a level that is well over $100 million in order to be considered conclusive.

In terms of economics, consideration must also be given to the overall risk profile to identify any tradeoffs between upside potential and downside risk. From the perspective of the overall business case conclusions, in addition to the economics, the financial, multiple accounts and optionality perspectives are important to the overall business case conclusions provided in Chapter 14.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 10.1.1.1; Page No.: 4

QUESTION:

Figure 10.1 shows the relative impact of 10 selected variables on two development plans. Where those 10 factors the only ones tested for possible inclusion in the probability study? If so, why? If not, what other factors were considered?

RESPONSE:

The ten factors shown in the tornado diagram in Figure 10.1 are the only factors that were tested for inclusion in the probability evaluations. These factors were selected because they effectively include all of the main economic assumptions used in the economic analysis of development plans. These ten factors could be tested and assessed as to the significance of their NPV impact.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.3; Page No.: 48-53

QUESTION:

Please explain how the decision was made to model Manitoba Hydro load for sensitivity analysis rather than include it in the probability analysis.

RESPONSE:

The probabilistic analysis allows for the comparison of factors that have a high impact on the development plans to be compared using a common set of base assumptions so that the impact of energy prices, capital costs and discount rates can be seen and understood. From a probabilistic analysis perspective, the effect of changes in energy prices, capital costs and discount rates cannot be isolated from the load impacts as they are combined with the effect of load changes and result in a very complex analysis. By treating load as a sensitivity, the impact of different levels of load can be clearly shown and understood for different development plans.

There is always more analysis that can be undertaken, however there are limitations to the availability of time and resources to do so. In preparing the NFAT submission, the decision was made to structure the analysis in a manner that would provide clear and understandable analyses. Including the factors of energy prices, capital costs and discount rates in the probabilistic analysis and using sensitivity analysis for load allows the effects to be demonstrated and understood.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.2; Page No.: 43-48

QUESTION:

Please explain how the decision was made to model climate change for sensitivity analysis rather than include it in the probability analysis.

RESPONSE:

Climate change impacts as they relate to temperature and precipitation have been assessed using sensitivity analysis since, although a potentially high impact factor, climate change is a more gradual impact factor that Manitoba Hydro can monitor and adapt to as necessary. The effects of climate change will continue to be studied. By analyzing climate change as a sensitivity the impacts are clearly shown for different development plans.

While there is always more analysis that can be undertaken, there are limitations to the availability of time and resources to do so. In preparing the NFAT submission, the decision was made to structure the analysis in a manner that would provide clear and understandable analyses. Including the factors of energy prices, capital costs and discount rates in the probabilistic analysis and using sensitivity analysis for climate change allows the effects to be demonstrated and understood.

In order to include a manageable and reasonable number of scenarios in the probabilistic analysis of twelve development plans, the range in the high impact factors of Energy Prices, Discount Rates and Capital Costs were considered to produce 27 potential outcomes. Including an additional factor with three outcomes would result in 81 scenarios, which was not manageable for the level of detailed analysis that was performed.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1; Page No.: 2-39

QUESTION:

It appears that future hydro production was not considered as a candidate for the probability analysis. If this is correct, why was it not considered? If it was considered, why was it excluded from the actual probability analysis?

RESPONSE:

In evaluations of development plans, including in the probabilistic analysis, for each load year into the future Manitoba Hydro applied a 99 year historic flow record capturing production costs and revenues over a broad range of system inflows. The uncertainty of future hydro production is essentially incorporated through averaging of the results from all of the flow cases in each load year.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.1; Page No.: 41

QUESTION:

Please provide a revised copy of Table 10.8 showing only the impact to NPV only during the critical flow year.

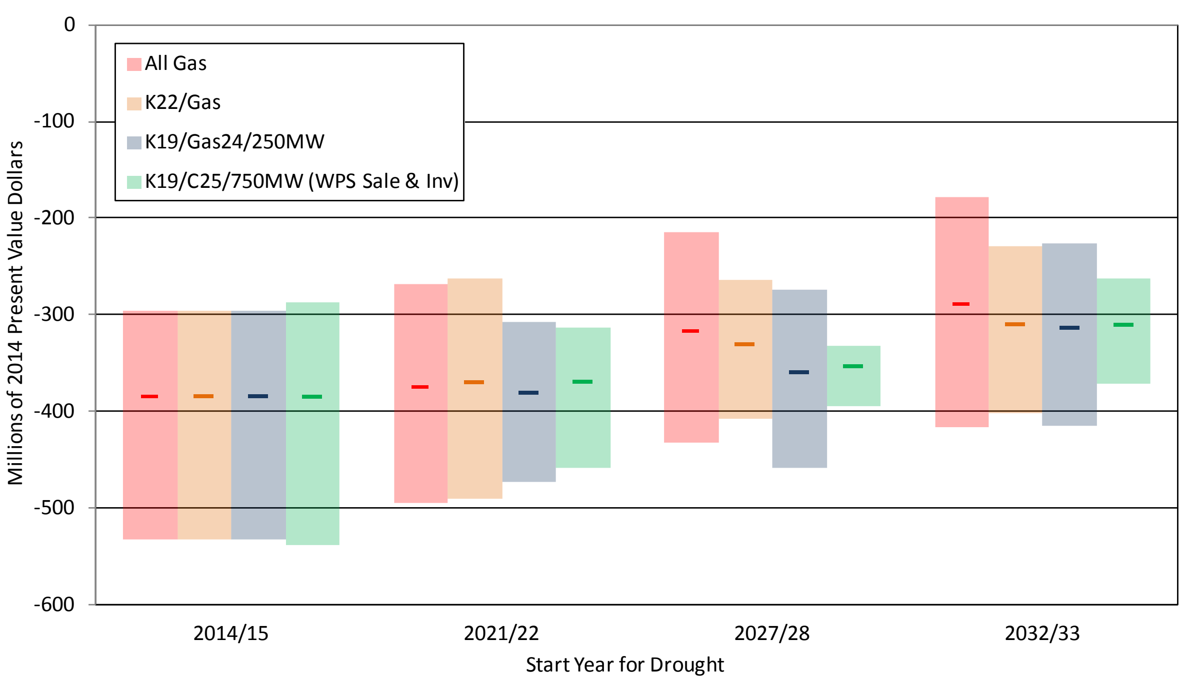
RESPONSE:

The following table shows the incremental change in NPV to the reference scenario (for the same four development plans presented in Table 10.8) at low, reference and high energy prices for a single year drought occurring in 2014/15, 2021/22, 2027/28 and 2032/33. The critical flow year, which was used for this analysis, is the fiscal year 1940/41. For illustrative purposes the information is plotted graphically in the same format as Figure 10.23 below the table.

1

Start year	Prices	All Gas	K22/Gas	K19/Gas24/250MW	K19/C25/750MW (WPS Sale & Inv)
		Impact on Reference Scenario NPV Millions of 2014$ @ 5.05 discount rate			
2014/15	Low	-296	-296	-295	-287
	Ref	-384	-384	-384	-384
	High	-532	-532	-532	-538
2021/22	Low	-268	-262	-307	-313
	Ref	-375	-369	-380	-369
	High	-494	-490	-473	-458
2027/28	Low	-215	-264	-274	-332
	Ref	-317	-330	-359	-353
	High	-432	-408	-458	-395
2032/33	Low	-179	-229	-226	-263
	Ref	-289	-310	-313	-310
	High	-416	-402	-414	-372

2



REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section: 2.2; Page No.: 5

QUESTION:

Please justify the assumption that there are no transmission limits in the Manitoba Hydro southern system and that the interface between MISO and this system is 100% reliable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section: 3; Page No.: 5

QUESTION:

Why was the 1984 flow year selected?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section: 3; Page No.: 5-6

QUESTION:

Please compare the hydro and thermal forced outage rate assumptions used in the MARS model referenced in Appendix 13.1 and the SPLASH modeling used for the NPV analysis presented in the NFAT application and explain any inconsistencies.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section 3; Page No.: 5

QUESTION:

Has Manitoba Hydro pursued reserve sharing agreements with utilities in Ontario or Saskatchewan? If so, why has Manitoba Hydro not entered into any reserve sharing agreements with these utilities? If not, why not?

RESPONSE:

Manitoba Hydro previously shared reserves with SaskPower. However, the expansion of the US interface, as explained in Section 5.2.2.3 of the NFAT Business Case, provided the opportunity for Manitoba Hydro to share reserves with a number of systems in the US. Manitoba Hydro's reserve obligation was reduced significantly by pooling resources with the US utilities because the combined US system was larger than the Saskatchewan system and because there was seasonal load diversity between Manitoba and the US Systems. For these same reasons, Manitoba Hydro continues to share reserves with the US (*i.e.* MISO), where the combined capacity of the Manitoba Hydro - MISO Contingency Reserve Sharing Group exceeds 130,000 MW.

REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section: 3; Page No.: 5

QUESTION:

Why were years 2022 and 2028 selected to estimate available energy from hydraulic stations?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 13.1 NFAT Reliability Evaluation; Section: 3; Page No.: 5

QUESTION:

Please justify the assumption that northern rectifier stations were 100% reliable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Section 2.5; Page No.: 5

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce the graph in Figure 2-1.

RESPONSE:

The following table contains a breakdown of Net Extraprovincial Revenue:

Extraprovincial Revenue – Water Rentals – Fuel and Power Purchased = Net Extraprovincial Revenue

Extraprovincial Revenues
(Millions of Dollars)

IFF09	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Extraprovincial Revenue	414.463	383.467	554.194	582.589	614.741	590.061	700.671	729.305	742.141	894.113	1 093.143	1 201.433	1 222.959	1 378.598	1 757.648	1 939.958	1 908.468	1 903.098	1 928.052	1 949.900			
Water Rentals	119.555	110.277	110.724	113.129	113.996	114.121	114.525	115.385	114.799	114.922	124.494	129.351	130.087	136.497	149.638	154.043	155.387	155.484	156.201	156.805			
Fuel and Power Purchased	102.759	131.106	247.772	249.192	259.387	268.436	296.291	340.636	361.969	440.347	418.074	434.502	459.441	473.339	459.143	491.685	419.728	395.053	424.221	445.468			
Net Revenue	192.149	142.084	195.698	220.268	241.358	207.504	289.855	273.284	265.373	338.844	550.575	637.580	633.431	768.762	1 148.867	1 294.230	1 333.353	1 352.561	1 347.630	1 347.627	-	-	-

IFF10	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Extraprovincial Revenue		443.630	461.017	499.331	510.030	529.259	610.829	620.944	645.888	654.225	803.670	983.545	1 128.025	1 162.235	1 310.645	1 668.103	1 782.335	1 808.309	1 812.687	1 834.488	1 847.069		
Water Rentals		120.554	115.107	111.079	111.693	112.097	112.517	112.877	112.545	112.688	113.354	120.566	126.664	128.205	134.816	147.027	151.436	152.583	152.797	153.330	153.763		
Fuel and Power Purchased		120.923	187.163	189.826	203.291	216.132	225.051	238.549	251.250	263.551	315.709	309.971	343.023	358.283	356.779	338.885	337.371	340.742	351.332	369.828	387.627		
Net Revenue	-	202.153	158.747	198.426	195.046	201.030	273.261	269.518	282.093	277.986	374.607	553.008	658.338	675.747	819.050	1 182.191	1 293.528	1 314.984	1 308.558	1 311.330	1 305.679	-	-

IFF11	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Extraprovincial Revenue			363.044	341.167	362.920	394.137	468.801	502.267	531.020	553.738	610.624	820.590	913.298	930.786	946.333	1 123.918	1 407.645	1 525.550	1 543.592	1 539.078	1 544.218	1 564.631	1 574.142
Water Rentals			119.300	105.900	112.470	112.878	113.089	113.334	112.777	112.739	114.449	122.757	127.586	128.597	128.447	134.796	148.258	152.810	152.970	153.176	153.508	154.508	155.093
Fuel and Power Purchased			145.664	182.478	158.040	186.602	192.701	204.156	220.353	235.649	248.970	255.987	256.520	268.739	301.121	281.557	279.427	301.272	320.129	332.417	347.058	358.644	372.061
Net Revenue	-	-	98.080	52.789	92.410	94.657	163.011	184.777	197.890	205.350	247.205	441.846	529.192	533.450	516.765	707.565	979.960	1 071.468	1 070.493	1 053.485	1 043.652	1 051.479	1 046.988

IFF12	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Extraprovincial Revenue				356.982	344.484	343.440	380.338	406.248	434.810	440.917	464.286	710.736	838.654	873.324	862.773	851.478	936.701	1 209.475	1 287.790	1 303.601	1 311.532	1 330.665	1 340.523
Water Rentals				117.040	115.791	111.602	111.785	111.975	111.665	111.728	112.763	121.428	126.386	127.851	127.152	126.340	134.149	147.265	150.573	150.943	151.188	152.148	152.690
Fuel and Power Purchased				142.906	166.203	179.164	190.955	206.100	220.674	230.075	230.979	253.253	264.238	277.575	292.332	317.755	280.731	276.687	291.091	304.327	317.821	327.575	341.048
Net Revenue	-	-	-	97.036	62.490	52.674	77.598	88.173	102.471	99.114	120.544	336.055	448.030	467.898	443.289	407.383	521.821	785.523	846.126	848.331	842.523	850.942	846.785

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Section 2.5; Page No.: 5

QUESTION:

If it has been calculated, please provide the data from Figure 2-1 for the 2013 IFF.

RESPONSE:

The 2013 Integrated Financial Forecast (IFF13) is not available at this time.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Section 2.5; Page No.: 5

QUESTION:

On page 5 of the 2012 IFF, the report states that “Compared to IFF11-2, net extraprovincial revenues are $2.9 billion lower in IFF12 by 2031/32.” Please provide a similar comparison for IFF12 versus the most current calculation for IFF13.

RESPONSE:

The 2013 Integrated Financial Forecast (IFF13) is not available at this time.

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Section: Section 3.0; Page No.: 10

QUESTION:

On page 10 of the 2012 IFF, the report states that "Over the 20-year forecast to 2031/32, capital expenditures are $3 969 million higher compared to the previous capital expenditure forecast, CEF11-2, mainly due to cost estimate increases for the Keeyask and Conawapa projects." Please provide a similar comparison for IFF12 versus the most current calculation for IFF13.

RESPONSE:

The 2013 Integrated Financial Forecast (IFF13) is not available at this time.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Please provide the amount of MW of ancillary services Manitoba Hydro can offer into the MISO market as an External Asynchronous Resource under the following scenarios: 1) no new interconnection is built, 2) a new 250 MW interconnection is built, 3) a 750 MW interconnection is built.

RESPONSE:

The amount of MWs of ancillary services Manitoba Hydro can offer into the MISO market as an External Asynchronous Resource (EAR) will remain the same regardless of the size of the new interconnection. MISO practices dictate that for security reasons no more than 20% of the system wide requirement for ancillary services can be carried by any single Resource. EAR is considered a single Resource.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Please provide the annual amount of MISO ancillary service market revenue Manitoba Hydro has received since 2009.

RESPONSE:

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

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

What Manitoba Hydro resources are currently capable of supplying ancillary services and what type and amount of ancillary services can each generator supply?

RESPONSE:

Manitoba Hydro resources which are currently capable of supplying ancillary services to the MISO market via the External Asynchronous Resource (EAR) are: Kettle Units 1-12, Long Spruce Units 1-10 and Limestone Units 1-10. The volume of ancillary services (any combination of Regulation, Spinning or Supplemental Reserves) which can be carried on a single generator has been limited to a maximum of 18 MWs.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Please compare Keeyask G.S.'s ability to supply ancillary services with that of a similar size natural-gas fired combined cycle plant.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Please compare Conawapa G.S.'s ability to supply ancillary services with that of a similar size natural-gas fired combined cycle plant.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Are any projected MISO ancillary services market revenues accounted for in the NFAT economic analysis? If so, please provide these estimates. If not, why not?

RESPONSE:

Revenues from MISO ancillary services are not included in the NFAT economic analysis because they are independent of the specific development sequence.

REFERENCE: Volume: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

Please provide the amount of MW of capacity Manitoba Hydro can offer into the MISO resource adequacy planning resource auction (either via direct offer into the auction or bilateral transaction with a counterparty in MISO), if: 1) no new interconnection is built, 2) a new 250 MW interconnection is built, 3) a 750 MW interconnection is built.

RESPONSE:

It is anticipated that all Manitoba Hydro owned resources, after the retirement of Brandon Unit 5 in 2019/20 as discussed in LCA/MH I-382, will be qualified to supply capacity surplus to the needs of Manitoba into the MISO market as a planning resource in accordance with the applicable MISO requirements. The applicable MISO requirements consider annual generation maximum capability testing results, station service requirements and unit forced outage rates.

Over the planning horizon, the sale of capacity is limited to the amount surplus to the needs of Manitoba in accordance with Manitoba Hydro Generation Planning Criteria. The values shown on the Winter Peak Capacity Supply and Demand Tables in Appendix 4.2 provide the amount of surplus exportable capacity over and above what has already been sold by bilateral contract.

Under the MISO market rules firm transmission service is required to sell capacity. With the existing 1850 MW of firm export transmission capacity into the MISO market and the addition of either 250 MW or 750 MW of export capacity, there is sufficient firm export transmission to sell the surplus capacity under each development plan.

It should be noted that as discussed in LCA/MH I-385, Manitoba expects to sell almost all of its surplus generation capacity under long term bilateral sales arrangements. Any surplus generation capacity not sold under a long term bilateral contract would be offered into the MISO planning resource auction.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

Please provide the annual amount of capacity export sales revenue Manitoba Hydro has received in the past five years. Please separately identify bilateral sales revenues and MISO voluntary capacity auction or planning resource auction revenues.

RESPONSE:

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

NOTE: Prior to June 2013, Manitoba Hydro was not eligible to participate in the MISO VCA

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

What Manitoba Hydro resources qualify for supplying capacity credits into the MISO resource adequacy planning resource auction and how much capacity credit can they supply?

RESPONSE:

Past 2019/20, it is anticipated that all Manitoba Hydro owned resources will be qualified to supply capacity surplus to the needs of Manitoba into the MISO market as a planning resource in accordance with the applicable MISO requirements. The applicable MISO requirements consider annual generation maximum capability testing results, station service requirements and unit forced outage rates.

At the present time, Brandon Unit 5 is not eligible for supplying capacity credits into the MISO resource adequacy planning resource auction for as noted on page 5 of Chapter 5, "Effective January 2010, The Manitoba Climate Change and Emissions Reduction Act restricted the operation of the Brandon coal unit to the support of emergency operations." However, as noted on page 41 of Chapter 4 of the filing "For planning purposes, it is assumed that Manitoba Hydro's last coal-fired steam turbine unit, of approximately 100 MW, will be retired in 2019/20"

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

Please compare Keeyask G.S.'s ability to supply capacity credits into MISO's planning resource auction (either via direct offer into the auction or bilateral transaction with a counterparty in MISO) with that of a similar size natural-gas fired combined cycle plant.

RESPONSE:

Keeyask G.S. would have the ability to supply capacity surplus to the needs of Manitoba into the MISO as a planning resource in accordance with the applicable MISO requirements. The additional capacity would be based on the net addition of 630 MW (Chapter 7, Table 7.6 – Capacity at Plant) as evaluated by MISO to consider annual generation maximum capability testing results, station service requirements and unit forced outage rates. This is the same capability that a similarly sized natural-gas fired plant could have in Manitoba.

The net capability of all resources can vary from month to month due to a number of factors. Depending on the type of generation, these factors can include ambient temperature, condensing water temperature and availability, fuels, steam heating loads, nuclear fuel management programs and, in the case of hydraulic generation, river discharge, reservoir levels and tailrace water levels.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

Please compare Conawapa G.S.'s ability to supply capacity credits into MISO's planning resource auction (either via direct offer into the auction or bilateral transaction with a counterparty in MISO) with that of a similar size natural-gas fired combined cycle plant.

RESPONSE:

Conawapa G.S. would have the ability to supply capacity surplus to the needs of Manitoba into the MISO as a planning resource in accordance with the applicable MISO requirements. The additional capacity would be based on the net addition of 1300 MW (Chapter 7, Table 7.6 – Capacity at Plant) as evaluated by MISO to consider annual generation maximum capability testing results, station service requirements and unit forced outage rates. This is the same capability that a similarly sized natural-gas fired plant could have in Manitoba.

The net capability of all resources can vary from month to month due to a number of factors. Depending on the type of generation, these factors can include ambient temperature, condensing water temperature and availability, fuels, steam heating loads, nuclear fuel management programs and, in the case of hydraulic generation, river discharge, reservoir levels and tailrace water levels.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

What are Manitoba Hydro's plans to participate in MISO's planning resource auction in the future and how does the development of new hydro generation resources and interconnections impact those plans?

RESPONSE:

Manitoba expects to sell almost all of its surplus generation capacity under long term bilateral sales arrangements. Any surplus generation capacity not sold under a long term bilateral contract would be offered into the MISO planning resource auction. The development of additional hydro in Manitoba would not change this plan, but of course would result in larger amounts of surplus capacity immediately after new hydro generation is constructed. All sales of surplus capacity are subject to the availability of firm transmission service.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 42

QUESTION:

Are any short-term capacity revenues from surplus capacity sales into MISO's planning resource auction (i.e. not through bilateral sales transactions) accounted for in the NFAT economic analysis? If so, please provide these estimates. If not, why not?

RESPONSE:

Manitoba Hydro assumes that all capacity surplus to the Manitoba load not already sold under a long term contract is bundled with dependable energy, and sold at the On-Peak Long Term Dependable Product price (See Appendix 9.3, Section 1.5.1.1 Electricity Export Price Forecast Products at page 10). This price is applied whether the capacity and dependable energy is expected to be sold on a bilateral contract basis or sold into MISO's planning resource auction.

For more information on Manitoba Hydro resources supplying surplus capacity into the MISO market, please see Manitoba Hydro's response to LCA/ MH I-382.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.3; Page No.: 9-25

QUESTION:

Please provide the calculations found in Figure 9.3 assuming that only 10 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.4; Page No.: 9-26

QUESTION:

Please provide the calculations found in Table 9.9 assuming that only 10 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.3; Page No.: 9-25

QUESTION:

Please provide the calculations found in Figure 9.3 assuming that only 20 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.4; Page No.: 9-26

QUESTION:

Please provide the calculations found in Table 9.9 assuming that only 20 years ("the detailed evaluation period") was used as the study period. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.1.3; Page No.: 37

QUESTION:

Please provide all the workpapers and reference documents used to derive the values for capital cost Percentage Differences of Low and High Capital Costs relative to Reference Capital Costs as shown in Appendix 9.3 Table 2.5. Where possible, please provide supporting material in electronic spreadsheet format with formulas intact and readable.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.1.1; Page No.: 4

QUESTION:

Figure 10.1 shows the relative impact of 10 selected variables on two development plans. Please provide all the workpapers in electronic form where possible that support the numbers shown in this figure.

RESPONSE:

Please see the attached spreadsheet named "Tornado Diagram – Highest Impact Factors.xlsx" for the calculations that support the impact of uncertainty in the 10 individual variables shown in Figure 10.1 of Chapter 10.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.4; Page No.: 24-35

QUESTION:

Please provide Figures 10.11 through 10.21 showing the NPV results over a 20-year period.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.5; Page No.: 36-39

QUESTION:

Please comment on whether the conclusions from the probabilistic analysis in Section 10.1.5 are still valid for the NPV over a 20 year period if Figures 10.11 through 10.21 are revised and used in the analysis.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.4; Page No.: 24-35

QUESTION:

Please provide Figures 10.11 through 10.21 showing the NPV results over a 35-year period

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.5; Page No.: 36-39

QUESTION:

Please comment on whether the conclusions from the probabilistic analysis in Section 10.1.5 are still valid for the NPV over a 35 year period if Figures 10.11 through 10.21 are revised and used in the analysis.

RESPONSE:

The magnitude of the incremental NPVs is much lower for the 35 year period primarily as a result of not capturing the economic benefits of the long-life assets and the additional reinvestment and O&M costs over the longer study period. The key conclusions from the probabilistic analysis provided in Chapter 10 do not change significantly whether assuming a total study life of 78 years, as provided in the NFAT submission, or a 35 year study period. The key conclusions as provided in Chapter 10 are summarized in the table below.

KEY CONCLUSIONS FROM NFAT SUBMISSION	78 YEAR STUDY PERIOD	35 YEAR STUDY PERIOD
Plans with No New Interconnection – Plans 1, 2, 3, 7 (Figures 10.11 and 10.12)		
All Gas (Plan 1) dominates Wind/Gas (Plan 3)	Yes	Yes
All Gas (Plan 1) has a significantly greater downside potential than K22/Gas (Plan 2) and SCGT/C26 (Plan 7)	Yes	No Long-life benefits are lower and reinvestment and operating costs are lower.
Wind/Gas (Plan 3) has the lowest overall expected value as a result of having the highest downside risk combined with a low upside potential	Yes	Yes
K22/Gas (Plan 2) has the highest expected value of all "no new interconnection" plans	Yes	Yes
Plans with 250 MW New Interconnection – Plans 4, 11, 13 (Figure 10.13)		
K19/Gas24/250MW (Plan 4) has lowest downside risk but also lowest upside potential; careful consideration must be given to the trade-offs between plans with a 250 MW interconnection due to differences in their risk profiles	Yes	Yes
K19/Gas24/250MW (Plan 4) has the highest expected value of all "250MW new interconnection" plans	Yes	Yes
Plans with 750 MW New Interconnection (WPS Sale & Investment) – Plans 5, 14 (Figure 10.14)		
The Preferred Development Plan (Plan 14) has the highest incremental NPV at Ref-Ref-Ref (when comparing Plan 14 and Plan 5)	Yes	Yes

KEY CONCLUSIONS FROM NFAT SUBMISSION	78 YEAR STUDY PERIOD	35 YEAR STUDY PERIOD
Plans with 750 MW New Interconnection (WPS Sale & Investment) – Plans 5, 14 (Figure 10.14) - continued		
The Preferred Development Plan (Plan 14) has the highest expected value	Yes	No Long-life benefits are lower and reinvestment and operating costs are lower.
Above the 50th percentile, Plan 14 lies to the right of K19/Gas25/750MW (WPS Sale & Inv) (Plan 5), reflecting significantly greater value primarily due to the availability of surplus power from the Conawapa G.S.	Yes	Yes same conclusions above 55th percentile
Below the 50th percentile, the risk profile is similar for the two plans but is driven by different factors	Yes	No Plan 5 shows a decrease in downside risk and Preferred Plan shows an increase in downside risk.
Plans with 750 MW New Interconnection without proposed WPS 300 MW Sale – Plans 6, 12, 15 (Figure 10.15)		
Range in the expected value of the three development plans	$115 Million K19/C31/750MW (Plan 12) has highest expected value	$265 Million K19/Gas31/750MW (Plan 6) has highest expected value

1

KEY CONCLUSIONS FROM NFAT SUBMISSION	78 YEAR STUDY PERIOD	35 YEAR STUDY PERIOD
Plans with 750 MW New Interconnection and Conawapa G.S. – Plans 12, 14, 15 (Figure 10.16)		
The Preferred Development Plan (Plan 14) has the highest expected value	Yes	Yes
K19/C25/750MW (Plan 15) has slightly more upside potential than the Preferred Development Plan above the 90th percentile; the benefit of this upside potential for Plan 15, however, is more than offset by the significant downside risk related to the exposure to low energy prices on surplus power unprotected by fixed prices	Yes	Yes
Summary of Plans with 750 MW New Interconnection – Plans 5, 6, 12, 14, 15 (Figure 10.17)		
Plans with highest expected value and upside potential.	Plan 12 and Plan 14 are higher in expected value when compared to the other plans; on the basis of both the expected value and upside potential, Plan 14 is the most attractive plan with a “750 MW interconnection” plan. Plan 12 is a reasonably close second choice.	Plan 5 and Plan 14 are higher in expected value when compared to the other plans; on the basis of both the expected value and upside potential, Plan 14 is the most attractive plan with a “750 MW interconnection” plan. Plan 5 is a reasonably close second choice.

KEY CONCLUSIONS FROM NFAT SUBMISSION	78 YEAR STUDY PERIOD	35 YEAR STUDY PERIOD
Comparison of Plans Across Categories		
Figure 10.18 – Plan 4 and Plan 2 When compared to K22/Gas (Plan 2), K19/Gas24/250MW (Plan 4) is dominant and has a higher expected value	Yes	Yes
Figure 10.19 – Plans 4, 5, 6 All conclusions are still valid	Yes	Yes
Figure 10.20 – Plans 11, 12, 13, 14, 15 All conclusions are still valid	Yes	Yes
Figure 10.21 – Plans 4, 12, 14 The economic results for Plans 4 and 14 are relatively close to each other making the plans competitive. Careful consideration must be given to the tradeoffs between the plans given the different characteristics of these plans. Further analysis of other perspectives (financial, multiple account and optionality) are important to the overall conclusions provided in Chapter 14.	The Preferred Development Plan (Plan 14) has a significantly higher incremental NPV under the reference scenario than that of Plan 4. Plan 14 has a higher expected value by only $114 million.	The Preferred Development Plan (Plan 14) and Plan 4 have essentially the same incremental NPV under the reference scenario. Plan 4 has a higher expected value by $226 million.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 8

QUESTION:

Please re-run the financial models for all the necessary plans shown on Figure 11.1 through Figure 11.3 where the revenue in every year is determined by maintaining the debt/equity ratio of 75/25 at the end of each year following first reaching the debt/equity ratio of 75/25 in 2031/2032. Provide a new Figure 11.1 for this new financial modeling.

RESPONSE:

Please see the following updated Figures 11.1 and 11.3 incorporating the annual rate increases required to achieve a 75:25 target debt/equity ratio in each year from 2033 to 2062. Please note that there is no change to Figure 11.2 as the requested change does not impact projected even annual rate increases in the first twenty years of the study period.

Figure 11.1

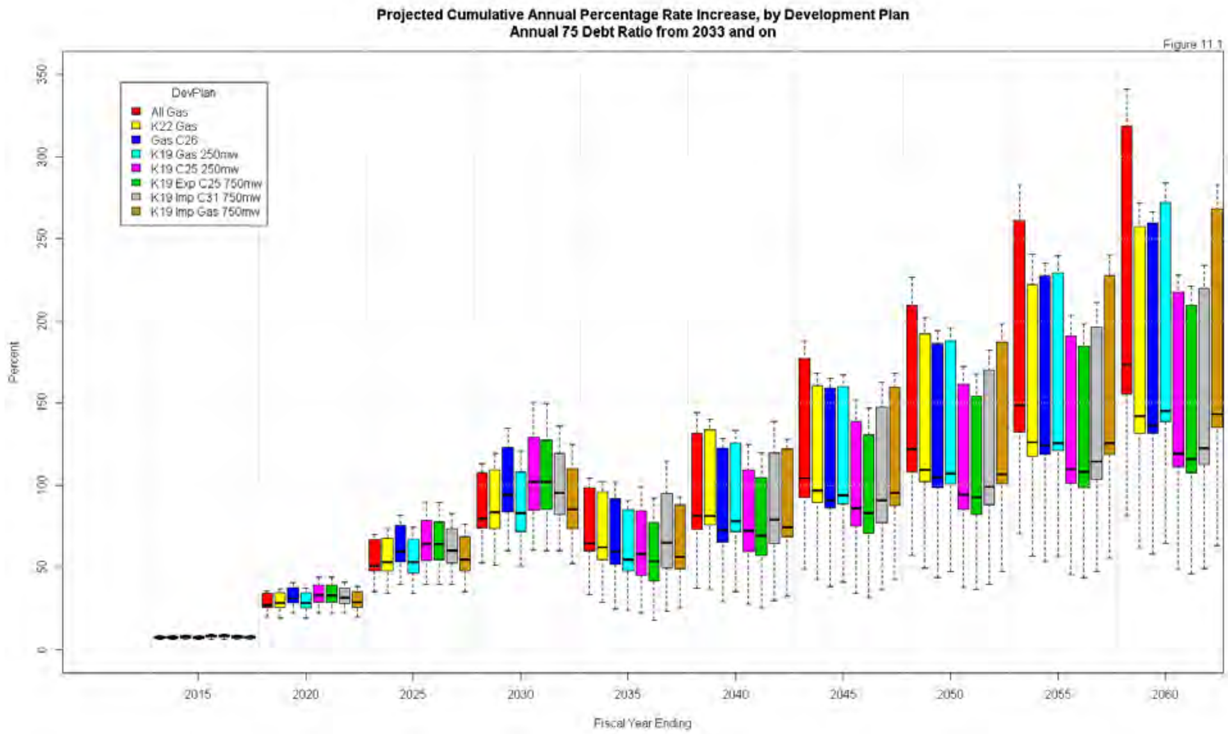
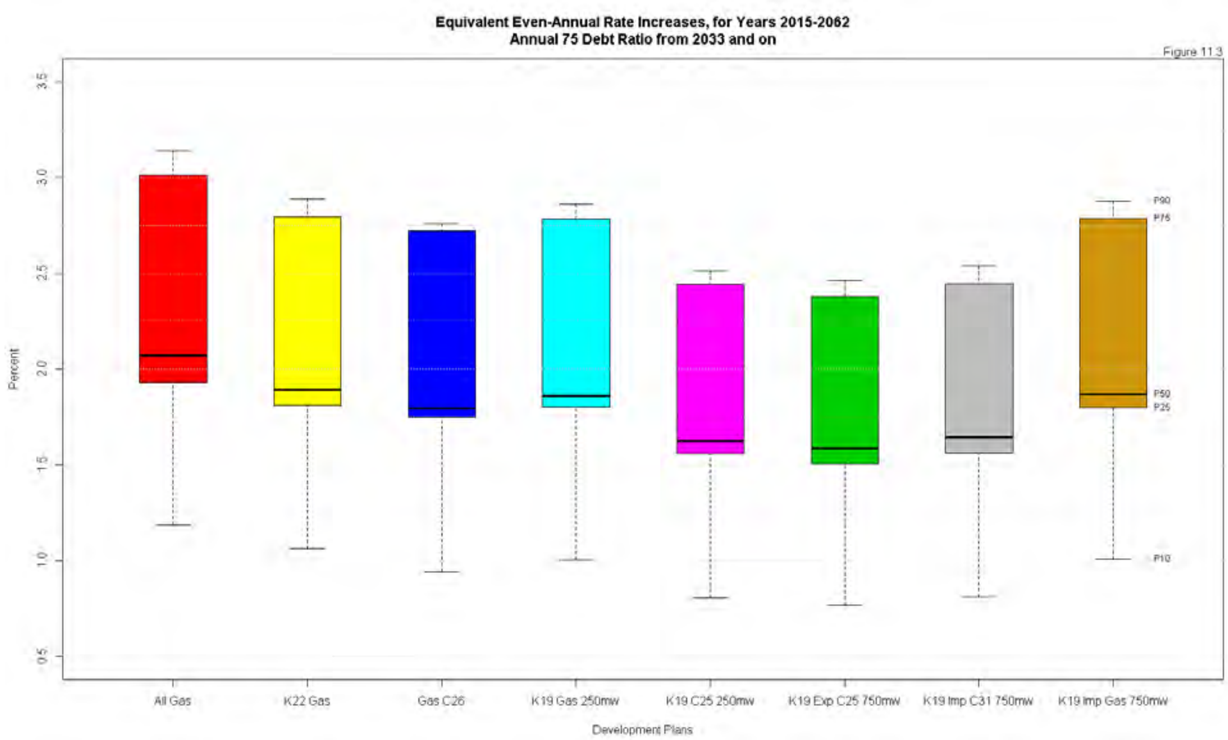


Figure 11.3



REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.1.1; Page No.: 18

QUESTION:

Please explain in detail and with numerical analysis how the Keeyask ownership rights of the KCN affect the revenue Manitoba Hydro requires from its customers. In doing so please include the "financial projections" and all workpapers preferably in electronic, working Excel file form that Manitoba Hydro Shared with KCN.

RESPONSE:

Manitoba Hydro is the majority and controlling owner in the Keeyask Hydropower Limited Partnership (KHLP). For forecast purposes, financial accounts are maintained separately for each entity; however, at the end of each fiscal year, the financial statements of KHLP are amalgamated with Manitoba Hydro's. Manitoba Hydro's accounts on the income statement and balance sheet reflect 100% of the revenues, expenses, assets and liabilities of KHLP. On the Manitoba Hydro balance sheet, the net assets of KHLP are offset by the Keeyask Cree Nation's (KCN) non-controlling ownership interest by an amount included in Current & Other Liabilities. The non-controlling interest shown in the pro forma financial statements in Appendix 11.4 reflects preferred dividends projected to be paid to the KCN.

Under the assumption of common ownership, non-controlling interest would reflect KCN's share of projected net income or losses. Additionally, Manitoba Hydro's projected net finance expense would be reduced by interest income accruing on equity loans to the KCN. Estimated impacts would be an approximate 1% strengthening of the debt/equity by 2031/32 resulting in slightly lower even-annual rate increases required to achieve the target 75:25 debt/equity ratio.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.1; Page No.: 21

QUESTION:

Please explain in detail what is meant on lines 18-21 "while adoption of the CEC recommendations is a risk to the Keeyask Project, it is not a third-party risk that is outside the control or consciousness of the decision maker, the Manitoba Government". Please detail the discretion the Manitoba Government has to accept, reject or modify conditions of the CEC recommendation. Please detail any control the government has over the CEC recommendations.

RESPONSE:

The quoted lines are referring to the fact that this is a 3rd party risk but that the 3rd party is ultimately the government of Manitoba that will decide i) how to respond to the Bipole III recommendations on regional cumulative effects assessment and ii) how to respond to any CEC or NFAT recommendations and conclusions on Keeyask.

The Manitoba Government has the discretion to accept, reject or modify conditions of the CEC recommendation. The government does not have control over the CEC recommendations.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.4.2.3; Page No.: 23

QUESTION:

Please explain how the delivery responsibility in each export power contract changes if the Keeyask G.S. project is delayed or cancelled should the listing of Lake Sturgeon under SARA be enacted.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.5.2; Page No.: 31

QUESTION:

Please provide the names and resumes of all Manitoba Hydro personnel that have been assigned to the "Project Manager and Construction Manager" functions referred to on line 9 on page 31 of Chapter 15. Please specifically note the individuals' role if any in the Wuskwatim project.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan; Section: 15.7; Page No.: 47

QUESTION:

Please provide total expected expenditures on Conawapa G.S. under the Preferred development Plan through December 31, 2017

RESPONSE:

The following table contains the total projected net expenditures for Conawapa GS under the Preferred Development Plan under the Reference Economics and Reference Capital Costs scenario up to December 31, 2017. Note that these expenditures are based on the Preferred Development Plan assuming construction starts late in 2017.

($Millions)

Fiscal Year Ending	Net Expenditures
Spent to Date	230
2013	56
2014	72
2015	66
2016	119
2017 *	172
Total	**715**

* Net Expenditures to December 31, 2017

REFERENCE: Appendix H Corporate Strategic Plan 2012-2013; Section: Goals; Page No.: 4

QUESTION:

Please reconcile the view of Manitoba Hydro on promoting energy conservation and innovation when the NFAT filing did not compare the costs and benefits of more DSM as compared to more hydroelectric development

RESPONSE:

Manitoba Hydro has been and continues to be committed to promoting energy conservation as noted in its responses to CAC/MH I-038(a) and CAC/MH I-222.

As outlined in Manitoba Hydro's responses to PUB/MH I-257 and CAC/GAC/MH I-018(b), DSM is a resource option considered as part of Manitoba Hydro's integrated resource planning process. Manitoba Hydro had intended to undertake a full DSM Market Potential Study, and then utilize the resulting information to perform an evaluation of DSM utilizing different levels of DSM in conjunction with different generation plans and exports. Unfortunately the study took longer to complete than expected and planned. As a result, the generation plan evaluations with the different levels of DSM could not be undertaken in time for the August 16, 2013 filing of the NFAT submission required by the NFAT schedule. Through the sensitivity analyses outlined in Chapter 12 of the submission, Manitoba Hydro did however assess the attractiveness of the Preferred Development Plan under increased levels of DSM, regardless of the cost of achieving the increased DSM savings. The DSM sensitivity and stress test indicated that in general the development plans analyzed benefit from increased levels of DSM. The Preferred Plan and Plan 4 (K19/Gas30/250MW) derive greater benefits from higher levels of DSM than the K23/Gas plan. Please also see Manitoba Hydro's response to CAC/MH I-225(a). As concluded in Chapter 12 of the submission: "analysis shows that the economic ranking of development plans remain the same under higher levels of DSM".

With the completion and subsequent filing of the DSM Market Potential Study with the August 16, 2013 submission, Manitoba Hydro had communicated that it intends to undertake prior to the NFAT hearing a generation plan study with two levels of DSM, the timing and extent of which will be dependent upon other demands on staff time in the process, including the need to respond to Information Requests.

REFERENCE: Appendix H Corporate Strategic Plan 2012-2013; Section: Economic Development; Page No.: 13

QUESTION:

Please provide the view of Manitoba Hydro being a driver of economic development when the NFAT filing shows that the Preferred Development Plan results in higher electric prices over the next 15 years as compared with other plans.

RESPONSE:

Manitoba Hydro drives economic development in the province in numerous ways. Most importantly, Manitoba Hydro drives economic benefits for the province with its ongoing operations and capital investments through employment, business transactions for goods and services and the payment of taxes and levies. As described in Chapter 13 of the NFAT business case, Manitoba Hydro's Preferred Development Plan will significantly and positively affect the Manitoba economy as a result of the demand for goods, services and labour generated by the construction and operation of the different projects in the different plans. The demand for labour is where there is the greatest potential for "economic rents" or net benefits to be generated.

In addition, Manitoba Hydro works closely with economic development agencies to attract new business, encourage expansion of existing business and to retain existing customers. While Manitoba Hydro's low rates are one factor, in particular for energy intensive companies, other factors such as reliability of supply, customer service policies, PowerSmart commercial and industrial programs and Manitoba's virtually carbon-free electricity are all ways that Manitoba Hydro can influence companies' investment decisions.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.7; Page No.: 23-26

QUESTION:

Please provide copies of all presentations to the Manitoba Hydro Board on the topic of wind resources or wind resource integration in the Manitoba Hydro system in the past three years along with all associated reports or studies.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.7; Page No.: 24-25

QUESTION:

Please provide a copy of the report from the Manitoba Hydro wind integration analysis conducted back in 2005-2006 including and in addition to the reports referenced in footnotes 2-3 of Appendix 9.3.

RESPONSE:

Please see Manitoba Hydro's response to GAC/MH I-014.

The remainder of the response to this information request contains Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Appendix B Manitoba Hydro 2011/12 Power Resource Plan; Section: 1.1; Page No.: 8

QUESTION:

Please provide the rationale and all supporting documentation for the limit on dependable energy from imports of 10% of Manitoba Hydro load.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-051 which has attached a copy of the report titled *Review of Generation Planning Criteria*, and please also refer to Manitoba Hydro's response to CAC/MH I-055 and MIPUG/MH I-041c.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.1.2; Page No.: 38

QUESTION:

Please provide the rationale and all supporting documentation for the limit on dependable energy from imports "to that which can be imported during the off-peak period, and will not exceed the quantity of export contracts in effect at the time, plus 10% of the Manitoba load".

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-051 which has attached a copy of the report titled *Review of Generation Planning Criteria*, and please also refer to Manitoba Hydro's response to CAC/MH I-055 and MIPUG/MH I-041c.

REFERENCE: Appendix B Manitoba Hydro 2011/12 Power Resource Plan; Section: 1.1; Page No.: 8; Chapter 4: The Need for New Resources, Section 4.3.1.2, page 38

QUESTION:

Please explain how the limit to dependable energy from imports of 10% of Manitoba Hydro load found in Appendix B is the same or different from the limit to dependable energy from imports discussed on lines 16-19 of page 38 of Chapter 4.

RESPONSE:

Response: As stated on lines 16-19 of page 38 of Chapter 4:

> “Imports may be considered as dependable energy resources under certain conditions. The total quantity of energy considered as dependable energy from imports is limited to that which can be imported during the off-peak period, and will not exceed the quantity of export contracts in effect at the time, plus 10% of the Manitoba load.”

The question is incorrect in stating that the limitation is “imports of 10% of Manitoba Hydro load”. As noted in the above quote, the limitation is “not [to] exceed the quantity of export contracts in effect at the time, plus 10% of the Manitoba load”.

The energy values found in Appendix B- Average Energy Supply and Demand Tables of the 2011/12 Power Resource Plan represent the average of all flow conditions and not dependable energy.

REFERENCE: Business Case; Section: Power Resource Plan; Page No.: Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 2.1, Page. 4

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Provide all data represented in Figure 1 in tabular form, including forecasted load by year for each forecast.

RESPONSE:

The table below provides the data shown in Figure 1.

	Energy Forecasts for 2007 - 2011 (GW.h)				
	2007	2008	2009	2010	2011
2011	26483	26544	25323	24739	24615
2012	26902	27107	25763	25142	25173
2013	27278	27428	26177	25807	25930
2014	27643	27721	26783	26180	26284
2015	28008	28019	27137	26599	26406
2016	28333	28272	27495	27055	26794
2017	28662	28614	27808	27362	27205
2018	28959	28955	28088	27657	27481
2019	29264	29295	28452	28016	27966
2020	29570	29635	28818	28381	28462
2021	29878	29973	29185	28748	28887
2022	30186	30311	29555	29120	29311
2023	30490	30647	29927	29496	29733
2024	30795	30983	30300	29878	30153

2025	31106	31323	30681	30269	30570
2026	31418	31660	31063	30663	30984
2027	31733	31998	31450	31062	31396
2028	32048	32335	31838	31464	31801
2029	32363	32672	32230	31869	32208
2030	32678	33009	32622	32277	32608
2031	32993	33346	33014	32686	33009
2032	33307	33683	33405	33094	33409
2033	33622	34020	33797	33503	33809
2034	33937	34357	34189	33911	34209
2035	34252	34694	34581	34320	34610
2036	34567	35031	34973	34728	35010
2037	34882	35367	35364	35137	35410
2038	35197	35704	35756	35545	35811
2039	35512	36041	36148	35954	36211
2040	35826	36378	36540	36362	36611
2041	36141	36715	36932	36771	37012
2042	36456	37052	37323	37179	37412
2043	36771	37389	37715	37587	37812
2044	37086	37726	38107	37996	38213
2045	37401	38063	38499	38404	38613
2046	37716	38400	38891	38813	39013

REFERENCE: Business Case; Section: Power Resource Plan; Page No.: Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 2.1, Page. 5

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Provide all data represented in Figure 2 in tabular form, including forecasted load by year for each forecast.

RESPONSE:

The table below provides the data represented in Figure 2.

	Peak Forecasts for 2007 - 2011 (MW)				
	2007	2008	2009	2010	2011
2011	4725	4745	4530	4604	4557
2012	4786	4837	4601	4677	4649
2013	4845	4883	4664	4776	4767
2014	4900	4927	4764	4842	4840
2015	4956	4972	4820	4913	4888
2016	5005	5009	4876	4990	4967
2017	5063	5062	4924	5048	5050
2018	5116	5122	4973	5106	5115
2019	5169	5183	5038	5171	5203
2020	5223	5242	5102	5238	5293
2021	5278	5302	5167	5305	5374
2022	5332	5362	5233	5373	5455
2023	5385	5421	5299	5442	5535
2024	5440	5480	5365	5511	5615
2025	5495	5541	5432	5583	5695

2026	5550	5600	5500	5655	5773
2027	5606	5661	5568	5728	5851
2028	5662	5720	5637	5802	5928
2029	5718	5779	5706	5877	6005
2030	5774	5838	5776	5952	6081
2031	5830	5897	5845	6027	6157
2032	5886	5956	5914	6102	6233
2033	5942	6015	5984	6177	6308
2034	5998	6074	6053	6252	6384
2035	6054	6133	6122	6327	6460
2036	6110	6192	6192	6402	6536
2037	6166	6251	6261	6477	6612
2038	6222	6310	6330	6552	6688
2039	6278	6369	6400	6627	6764
2040	6334	6428	6469	6702	6840
2041	6390	6487	6539	6777	6916
2042	6446	6546	6608	6852	6992
2043	6502	6605	6677	6927	7068
2044	6558	6664	6747	7002	7144
2045	6614	6723	6816	7077	7220
2046	6670	6782	6885	7152	7296

1

REFERENCE: Business Case; Section: Power Resource Plan; Page No.: Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 2.1, Page No. 4-7

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan

QUESTION:

Please explain and provide all supporting material, i.e. reports and workpapers, that justify the higher annual growth rates for the 2012 energy and winter peak load forecasts as compared to prior year forecasts.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 2.1, Page No. 5

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Please explain why the 2012 near-term forecasted winter peak demand was reduced by 158 MW from the 2011 forecast "primarily due to a correction in the Distribution Losses calculation" yet the forecasts are essentially the same by the end of the forecast period. Provide all documentation and analysis supporting your response.

RESPONSE:

The correction of the distribution losses of the winter peak in the 2012 Forecast was 135 MW in 2012/13 rising to 151 MW in 2020/21 and then rising to 171 MW in 2030/31. Given all forecast inputs and assumptions remained equal, the 2012 Forecast would have been 171 MW lower than the 2011 Forecast. However, the overall annual growth rate for the 2012 forecast is slightly higher than the 2011 forecast resulting in the 2012 Forecast being similar to the 2011 forecast at the end of the forecast period.

Please refer to page 16 of the 2012 Electric Load Forecast, included as Appendix C of the filing, for a description of the change between the 2011 and 2012 Gross Total Peak forecast.

REFERENCE: Business Case; Section: Power Resource Plan; Page No.: Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 3.1, Page No. 11

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Provide an update on the status of the "Proposed Federal Coal-Fired Electricity Generation Regulation."

RESPONSE:

In 2012 Environment Canada finalized the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (2012) under the *Canadian Environmental Protection Act.* As described in ***Appendix 7.2 – Range of Resource Options***, page 244, these coal regulations will come into effect July 1, 2015. They will require that a performance standard of 420 tonnes/GW.h be met by all new coal-fired units and as well as units that have reached the end of their useful life (defined as 50 years from the date of commissioning).

Brandon Unit 5, Manitoba Hydro's sole remaining coal-fired generating unit, is assumed to remain available until 2019. The federal coal regulations would not place any additional constraints on this unit (beyond those set out in Manitoba's *Coal-Fired Emergency Operations Regulation)* until December 31, 2019.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 3.1, Page No.'s 10-11

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Identify any federal or provincial legislation that prevents the continued dependence on Brandon Unit 5 for capacity purposes beyond 2019.

RESPONSE:

This question requires production of a legal opinion which Manitoba Hydro respectfully declines to provide. By way of general response, the context for continued operation of Brandon Unit 5 beyond 2019 is uncertain. Both provincial and federal coal regulations limit operation to an emergency standby role. While the provincial regulation specifies drought as an emergency circumstance, the federal regulation would require the Minister responsible for the Emergency Measures Act of Manitoba to declare a state of emergency for prolonged operation under drought conditions. By 2030, the federal coal regulations will prohibit the operation of the unit at the current level of emissions.

The current provincial Environmental Act License for operation of Brandon Unit 5 is under review. In 2006, Manitoba Hydro filed a plan to operate beyond 2006 until approximately 2020. The outcome of a licence review, particularly if operation beyond 2019 is sought, would be uncertain.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 3.1, Page No.'s 13-14

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Provide a table summarizing the pricing terms of each of the Firm Import Contracts listed in Table 3 including cost of energy and capacity by year by contract

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 3.1, Page No.'s 13-14

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Has Manitoba Hydro engaged in any negotiations to extend the firm import contracts listed in Table 3? If so, please provide a summary of the status of those negotiations. If not, why not?

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Section 3.1, Page No.'s 13-14

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Provide any evidence indicating that Manitoba Hydro would not be able to extend the firm import contracts listed in Table 3 upon expiration.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Power Resource Plan; Commercially Sensitive Information: 2012/13 Power Resource Plan, Appendix U, Page 174

PREAMBLE: Regarding Manitoba Hydro's 2012/13 Power Resource Plan:

QUESTION:

Please reconcile the base cost estimate for the Notigi GS resource with the estimate provided in the NFAT documentation. Provide all documentation and analysis explaining the difference.

RESPONSE:

The base cost estimate for the Notigi Generating Station provided in the 2012/2013 Power Resource Plan was $0.6 billion (2012$). In the NFAT Business Case submission, the base cost estimate for the Notigi Generating Station was provided as $1.0 billion (2014$). The difference in cost estimates can be attributed to the NFAT estimate containing the following additional elements:

- a revision to the original generating station estimate incorporating recent experience with Wuskwatim and Keeyask
- the addition of associated transmission costs
- the addition of real escalation
- the conversion of the estimate from 2012$ to 2014$

The tables below provide the requested reconciliation.

2012\13 PRP Notigi Base Cost Estimate	$billions
Generating Station (2012$)	0.6

NFAT Submission Notigi Base Cost Estimate	
Generating Station – Revised Estimate (2012$)	0.7
Transmission (2012$)	0.2
Generating Station Real Escalation	0.05
Escalation from 2012$ to 2014$	0.05
Total Notigi Base Cost Estimate 2014$	1.0

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: For each contract modeled in the NFAT analysis.

QUESTION:

What date was the contract assumed to expire? If any of these dates are different from the defined contract term, or term listed in the latest term sheets provided, please explain the difference.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: For each contract modeled in the NFAT analysis.

QUESTION:

Were any contracts assumed to be renewed and if so, what contract terms did Manitoba Hydro assume to perform the modeling?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: 2013 Electricity Export Price Forecast, Section 2.1.4, Page Nos. 14-15

QUESTION:

Was any economic modeling in the NFAT of the long-term contracts reliant on Manitoba Hydro's Long Term Dependable product price? If so, please describe this modeling and provide an annual breakdown of the amount of sales in dollars and MWh assumed to be made using this product forecast.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: 2013 Electricity Export Price Forecast, Section 2.1.4, Page Nos. 14-15

QUESTION:

Is the Long Term Dependable market product incorporated into the SPLASH model piecewise linear relationship of export market prices? If so, how?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: 2013 Electricity Export Price Forecast, Section 2.1.4, Page No. 15

QUESTION:

How long has the premium applied to the Long Term Dependable market product remained at its current level and what level was it at before being changed to its current level?

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 - Trade Secret & Confidential

QUESTION:

For each contract or term sheet where power delivery has not yet commenced, please confirm whether the Company has performed any contract analysis or risk assessment, and if so, provide a copy of this assessment or analysis.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each power contract, please indicate whether the agreements are final.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each final power contract, please indicate whether there could be any amendments or side-deals associated with these agreements, and if so, provide a copy of any such document.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each term sheet, please discuss whether these agreements are considered final or whether negotiations are ongoing, and if so, what terms are still subject to negotiations associated with these agreement, and if so, provide a copy of any such document.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

If the Company has prepared any synopsis or outline of the contracts or terms sheets, please provide copies.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each contract and term sheet, please discuss the Company's pricing strategy for firm power and provide any analysis that supports the selection of this strategy.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each contract and term sheet, please discuss the Company's selection of investment grade credit rating scores, and provide any analysis that supports the selection of these ratings.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each contract and term sheet, please discuss the Company's rationale for pricing environmental attributes, and provide any analysis that supports the selection of this strategy.

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each contract and term sheet, please discuss the Company's pricing strategy for capacity and provide any analysis that supports the selection of this strategy.

RESPONSE:

Please refer to Manitoba Hydro’s response to LCA/MH I-441.

REFERENCE: Business Case; Section: export contract; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

For each power contract requiring state regulatory approval, please provide an update on the status of that approval process along with identifying docket numbers.

RESPONSE:

The following are the contracts that required Minnesota state regulatory approval and their status:

NSP 375/325 SPS – complete, docket #10-633;

NSP 350 SD – complete, docket #10-633;

NSP 125 SPS – complete, docket #10-633;

MP 250 SPS – complete, docket#11-938;

MP Energy Exchange Agreement – complete, docket#11-938.

REFERENCE: Business Case; Section: export contract; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

In some cases, the Company sells some products, for instance energy, while retaining rights to others, for example ancillary services. Has the Company performed any analysis to identify either conflicting incentives provided by, or optimization of the economics associated with, sales of the contract energy and related requirements under the export contracts, and the Company's marketing strategy for retained products like ancillary services? Please provide all such analyses, whether qualitative or quantitative, if so. If not, why not?

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: export contract; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

With respect to Performance Assurance provisions, has the Company performed any analysis of the risks it faces with leaving the "Second Party" with the option of deciding which form of assurance it will provide the "Requesting Party?"

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: Export Contract; Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

With respect to Performance Assurance provisions, if the pricing under the export contracts gets substantially out of market relative to other power supply options available in the wholesale markets, that is the contract price is substantially "above market" or "below market" (howsoever measured), does that condition alone allow the exposed party to request Performance Assurance of the Second Party? If not, what is the Company's rationale for excluding such exposures from the Performance Assurance provisions?

RESPONSE:

The response to this Information Request includes Commercially Sensitive Information and has been filed in confidence with the Public Utilities Board.

REFERENCE: Business Case; Section: export contract; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

Has the Company assessed the quality of, and risks associated with, a Guaranty Agreement with a counterparty that is rated just above "Investment Grade" (e.g. BBB- from S&P)? If so, please provide all such analyses, whether qualitative or quantitative. If not, why not?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Business Case; Section: export contract; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

PREAMBLE: NOTE QUESTION REFERS TO CONFIDENTIAL LANGUAGE - Please refer to the Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2 Trade Secret & Confidential

QUESTION:

Has the Company's internal or external counsel prepared any opinion letter or related analysis of the export contract risks to MH? If so, please provide any and all such opinions or analyses. If not, why not?

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.

REFERENCE: Power Market Trading Contracts; Page No.: Commercially Sensitive Information: Manitoba Hydro Export Contracts and Term Sheets Volumes 1 &2

QUESTION:

Please provide all Company Power Market Trading Contracts that are dependent upon or affected by the NFAT development project.

RESPONSE:

This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.