Section:	Tab 1	Page No.:	1
Topic:	Letter of Application		
Subtopic:	Approvals Requested		
Issue:	Changes to Approvals Requested		

PREAMBLE TO IR (IF ANY):

QUESTION:

In light of the Board Orders issued since January 2015 and any other events that may have occurred since the Application was filed are there: i) any revisions that are required to approvals requested or ii) the Application as filed? If so, what are they?

RATIONALE FOR QUESTION:

The Board has issued various Letters and Orders since the Application was initially filed regarding the scope of the proceeding. In addition other events may have occurred that would require either an update to the Application or a change in the approvals requested.

RESPONSE:

There are no revisions required to the approvals requested in Tab 1 of the Application as the letters and Orders issued by the PUB, since the Application was filed, do not result in Manitoba Hydro withdrawing any of its requested approvals but rather clarifies the process and timing of the review of these approvals by the PUB.

Manitoba Hydro notes the following with respect to the letters and Orders issued by the PUB since the Application was filed:

- With respect to approval item 1a), Manitoba Hydro requested an electric rate increase of 3.95% for the 2015/16 fiscal year on an interim basis effective April 1, 2015. The PUB has indicated in Order 17/15 that it will not consider an interim rate increase effective

April 1, 2015 but rather will issue a final Order with respect to a rate increase for 2015/16 after the current regulatory proceeding concludes.

- With respect to approval item 1b), Manitoba Hydro requested an electric rate increase of 3.95% for the 2016/17 fiscal year effective April 1, 2016. The PUB has indicated in Order 17/15 that it did not intend to approve a rate increase to be effective April 1, 2016 in the current proceeding. However, the PUB also indicated that it may alter or review this decision if there are any new facts or material changes in circumstances that arise during the current regulatory proceeding. In addition, the PUB also indicated that the forecast information for 2016/17, as filed by Manitoba Hydro, will be reviewed by all parties during the hearing and that it will be open to provide further direction, in its final GRA Order, as to any additional information to be filed and considered before determining whether any process should be instituted for possible April 1, 2016 interim rates.

- With respect to approval item 1e), Manitoba Hydro requested approval of Time of Use Rates for GSL customers >30kV effective April 1, 2016. In Order 18/15, the PUB indicated it will review this request at the upcoming Cost of Service review that is to be scheduled later in 2015.

Section:	Tab 1	**Page No.:**	3
Topic:	Letter of Application		
Subtopic:	Monthly Bill Impacts		
Issue:	Residential Bill Impact		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table that for each of the years 2008/2009 through 2013/14 sets out the number of Residential Basic customers: i) with electric heat; ii) without electric space heating and iii) in total. In each case, please also provide both actual and weather normalized annual usage (in total and per customer). Also please clarify whether the kWhs reported include or exclude estimated usage by flat rate water heaters.

RATIONALE FOR QUESTION:

To confirm the typical usage of different categories of Residential customers in order to provide insight into relative impacts on different types of use of rate increases.

RESPONSE:

The energy provided in the following table does not include the estimated usage of flat rate water heaters.

Residential Basic Total Usage

Fiscal Year	Electric Heat Billed # of Custs	Electric Heat Billed Usage (GW.h)	Electric Heat Billed W/A Usage (GW.h)	Other # of Custs	Other Usage (GW.h)	Other W/A Usage (GW.h)	Residential Basic Total # of Custs	Residential Basic Total Usage (GW.h)	Residential Basic Total W/A Usage (GW.h)
2008/09	149,404	3,990	3,845	287,859	2,858	2,866	437,263	6,847	6,710
2009/10	153,132	3,861	3,935	288,578	2,925	3,005	441,710	6,786	6,940
2010/11	156,708	3,954	4,021	289,174	2,999	3,032	445,882	6,952	7,053
2011/12	160,600	3,787	4,097	290,148	3,031	3,039	450,748	6,818	7,137
2012/13	164,994	4,121	4,181	291,136	3,103	3,047	456,130	7,223	7,228
2013/14	169,582	4,636	4,237	292,692	3,131	3,013	462,274	7,767	7,249

Residential Basic Average Use

Fiscal Year	Electric Heat Billed # of Custs	Electric Heat Billed Ave Use (kW.h)	Electric Heat Billed W/A Ave Use (kW.h)	Other # of Custs	Other Ave Use (kW.h)	Other W/A Ave Use (kW.h)	Residential Basic Total # of Custs	Residential Basic Total Ave Use (kW.h)	Residential Basic Total W/A Ave Use (kW.h)
2008/09	149,404	26,703	25,735	287,859	9,927	9,955	437,263	15,659	15,347
2009/10	153,132	25,213	25,695	288,578	10,137	10,413	441,710	15,363	15,711
2010/11	156,708	25,229	25,656	289,174	10,369	10,485	445,882	15,592	15,817
2011/12	160,600	23,577	25,512	290,148	10,447	10,476	450,748	15,125	15,833
2012/13	164,994	24,974	25,339	291,136	10,658	10,465	456,130	15,836	15,846
2013/14	169,582	27,341	24,983	292,692	10,696	10,294	462,274	16,802	15,682

Section:	Tab 1	Page No.:	3
Topic:	Letter of Application		
Subtopic:	Monthly Bill Impacts		
Issue:	Residential Bill Impact		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table that for each of the years 2008/2009 through 2013/14 sets out the number of Residential Seasonal customers: i) with electric heat; ii) without electric space heating and iii) in total. In each case, please also provide both actual and weather normalized annual usage (in total and per customer).

RATIONALE FOR QUESTION:

To confirm the typical usage of different categories of Residential customers in order to provide insight into relative impacts on different types of use of rate increases.

RESPONSE:

Please see the table below for the number of residential seasonal customers with electric heat, without electric space heating and in total. Manitoba Hydro does not perform any weather adjustment on the Residential Seasonal rate class. Meters are read for Seasonal customers twice a year (April and October). This data frequency is insufficient to properly account for monthly fluctuations due to weather.

Residential Seasonal Customers

Fiscal Year	Electric Heat Billed Customers	Electric Heat Billed Usage (GW.h)	Electric Heat Billed kW.h per Cust	Non Electric Heat Billed Customers	Non Electric Heat Billed Usage (GW.h)	Non Electric Heat Billed kW.h per Cust	Total Customers	Total Usage (GW.h)	Total kW.h per Cust
2008/09	7,600	38.7	5,092	13,048	35.7	2,733	20,648	74.4	3,601
2009/10	7,825	43.8	5,601	13,015	37.6	2,892	20,840	81.5	3,909
2010/11	8,084	41.6	5,150	12,865	35.3	2,747	20,949	77.0	3,675
2011/12	8,213	46.3	5,638	12,631	36.8	2,913	20,844	83.1	3,987
2012/13	8,325	44.4	5,337	12,405	36.6	2,954	20,730	81.1	3,911
2013/14	8,502	52.9	6,217	12,255	39.6	3,233	20,757	92.5	4,455

Section:	Tab 1	**Page No.:**	3
Topic:	Letter of Application		
Subtopic:	Bill Impacts		
Issue:	Customer Sensitivity		

PREAMBLE TO IR (IF ANY):

QUESTION:

How has Manitoba Hydro identified/determined "customer sensitivity to rate increases" (per line 34)?

RATIONALE FOR QUESTION:

In the Application Manitoba Hydro states that it has "considered customer sensitivity to rate increases". The issue goes to the pace and magnitude of rate changes.

RESPONSE:

Manitoba Hydro believes rate stability and predictably to be important considerations in determining a customer's sensitivity to rate increases, and through its proposed 3.95% rate increases for 2015/16 & 2016/17, has balanced these considerations with the need to invest in its system to meet growing energy requirements, address capacity needs, and replace aging utility assets.

As discussed in Tab 2, considering the financial outlook projected in MH14, there is financial justification for requesting rate increases in the order of 5.5% to 6.0% for the next four years in order to reduce the losses that are projected in the next 10 year period and maintain financial reserves at current levels. However, Manitoba Hydro recognizes that the rate increases that would be necessary to maintain its financial ratios at or above targets in the near to medium term, would be financially challenging for its customers. Further, this would be inconsistent with Manitoba Hydro's approach of smoothing rate increases over time in order to promote rate stability.

As also discussed in Tab 2, Manitoba Hydro has outlined the projected impact on future rate increases if near-term rate increases lower than 3.95% are implemented in the next four years. As demonstrated in Figure 2.26 in Tab 2, with 2% rate increases for the next 4 years, Manitoba Hydro would require 8% rate increases for the following five years, and with 2.95% rate increases for the next four years, Manitoba Hydro would require 6% rate increases in the five years that follow. This analysis demonstrates how future rate increases would have to significantly increase in order to compensate for lower rate increases obtained in the near term.

Based on this range of alternatives, Manitoba Hydro maintained the minimum proposed rate increases at 3.95% with consideration of customer sensitivity to rate increases. Manitoba Hydro believes that gradually raising rates by the minimum 3.95% rate increases is in the customers' best interest as this maintains rate stability and predictability during a period where rate increases are necessary to maintain the Corporation's financial strength and avoid the need for sudden or larger rate increases in the near future.

Section:	Tab 1	Page No.:	3
Topic:	Letter of Application		
Subtopic:	Bill Impacts		
Issue:	Customer Sensitivity		

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on these sources, what is Manitoba Hydro's understanding regarding customer sensitivity to rate increases? Please address in terms of both the sensitivity to different levels of rate increase and stability of rate increases overtime.

RATIONALE FOR QUESTION:

In the Application Manitoba Hydro states that it has "considered customer sensitivity to rate increases". The issue goes to the pace and magnitude of rate changes.

RESPONSE:

Please see the response to COALITION/MH-I-3a.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

To what year are the strategies and targets set out in the CSP (Appendix 2.1, page 18)) are meant to apply?

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

The measures and targets on the Corporate Dashboard, as provided in Appendix 2.1, are applicable to the 2014/15 year. Although provided jointly in Appendix 2.1, the current CSP is a contextual document. The Corporate Dashboard is a separate document with a different review cycle.

As the overall strategic direction of Manitoba Hydro involves multi-year planning, decision and approval processes, Manitoba Hydro updates and re-publishes the CSP every three years unless changes to the strategic direction prompt a need for an earlier revision.

The measures and targets in the Corporate Dashboard are confirmed on an annual basis. Additional measures and targets may also be added throughout the year if circumstances dictate.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the CSP in Appendix 2.1 (dated November 2013) is meant to apply to the 2013/14 year, please explain why the DSM targets in the CSP differ from those set out in Tab 10, Figure 10.1.

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

As discussed in COALITION/MH-I-4(a), the DSM targets provided in Appendix 2.1 apply to the 2014/15 year. Tab 10, Figure 10.1 reflects the targets and actual results from 2013/14.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the CSP provided in Appendix 2.1 is not applicable to the 2013/14 year, please indicate for which year it is applicable and provide the actual results (similar to Figure 10.1).

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

The measures and targets provided in Appendix 2.1 are applicable to the 2014/15 year. Results for 2014/15 are not yet available as the fiscal year has not yet ended.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

The CSP provided in Appendix 2.1 is dated November 2013. If a more recent CSP is available (e.g. for 2014) please provide and indicate to what year it is applicable.

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

The CSP provided in Appendix 2.l is the most current CSP. As noted in the response to COALITION/MH-I-4a, Manitoba Hydro updates and publishes its CSP every three years, unless changes to the strategic direction prompt a need for an earlier revision.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

If a more recent CSP is not available, please indicate whether the targets set out in the November 2013 CSP should be considered to be applicable to the years 2014/15 through 2016/17 covered by the Application.

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

As indicated in the response to Coalition/MH I-4a, the CSP is a contextual document and is republished every three years unless changes to the strategic direction prompt a need for an earlier revision. The targets set out in the Corporate Dashboard included in Appendix 2.1 are applicable to the 2014/15 fiscal year. Targets for the 2015/16 and 2016/17 Corporate Dashboards will be confirmed at the start of each fiscal year.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

If they are not applicable what are the relevant targets for these years that were used for planning purposes.

RATIONALE FOR QUESTION:

Clarify the applicability of the CSP provided in Appendix 2.1, whether more recent recent CSPs are available and what strategies/targets are applicable to the rate years addressed by the Application. The strategies and targets are one mechanism to assess the prudence of expenditures.

RESPONSE:

The Corporate dashboard is a summary of targets developed throughout the integrated planning process for the current year. For example, financial strength measures on the Dashboard reflect the results of IFF planning processes. DSM targets refer directly the Power Smart Plan. If there are discrepancies due to timing, the source documents (i.e. IFF, PSP) will prevail.

The Corporate Dashboard does not set targets for future years.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the Financial Strength targets, please provide the budget values for each measure. Please also indicate (and provide if not already part of the record for this proceeding) the relevant source document (e.g. IFF).

RATIONALE FOR QUESTION:

Clarify the CSP's financial targets and their bases. The impact on financial target is one measure of reasonableness of rate increases.

RESPONSE:

Please see Figure 10.1 on page 12 of Tab 10 for the Corporate Performance Dashboard for the budget and results as at March 31, 2014.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Unlike previous CSPs (e.g. the 2011/12 CSP filed in the last GRA), the current CSP does not include separate measures and targets for Electric and Gas O&M. Please explain why this is the case.

RATIONALE FOR QUESTION:

Clarify the CSP's financial targets and their bases. The impact on financial target is one measure of reasonableness of rate increases.

RESPONSE:

The CSP's primary purpose is to communicate strategic direction and priorities to employees as an integrated and aligned gas and electric utility. The commitments to carefully manage costs, utilize resources effectively, and provide maximum value to stakeholders and ratepayers apply to all segments of the business and not separately to electric and gas. In addition, corporate communications with customers and external stakeholders are from Manitoba Hydro as an integrated energy utility.

As the separate Electric and Gas O&M results are specifically for rate-setting purposes, they have been provided in the General Rate Application (Appendix 3.3 Consolidated Integrated financial Forecast IFF14).

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain the basis for the customer satisfaction measure used in the current CSP (i.e. CSTS – Manitoba Hydro quarterly survey).

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

The Customer Service Tracking Study (CSTS) is used as the measure for customer satisfaction in the current CSP as it provides:

- more timely results due to its quarterly fielding (compared to annual fielding by the CEA);
- more accurate measurement due to its larger sample of Manitoba respondents (2,000 randomly selected Manitoba households annually versus 200 to 500 households by the CEA);

- more reliable results because the survey is carried out by Manitoba Hydro (versus being under the control of multiple utilities outside of the Manitoba jurisdiction); and
- scientifically representative results due to its probability sampling methodology that allows results to be extrapolated to the survey population with statistically determined degree of error (+ 4.4% 19 times out of 20 for overall CSTS results versus no such option for the CEA survey which uses a non-probability, web panel sampling methodology).

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

For how long has Manitoba Hydro been undertaking this "survey" and how frequently is it done.

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

Manitoba Hydro established the Customer Satisfaction Tracking Study (CSTS) in June 1999 to track customer perceptions of its customer service, corporate citizenship and corporate image. The CSTS is a quarterly telephone survey of 500 randomly selected residential Manitoba households contacted at the end of each quarter by an independent market research firm.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the customer satisfaction measure results from any of these surveys undertaken in the last five years.

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

The latest results for the Customer Satisfaction Tracking Study (CSTS) are attached. These results are based on survey questions fielded during January 29 – February 1, 2015.

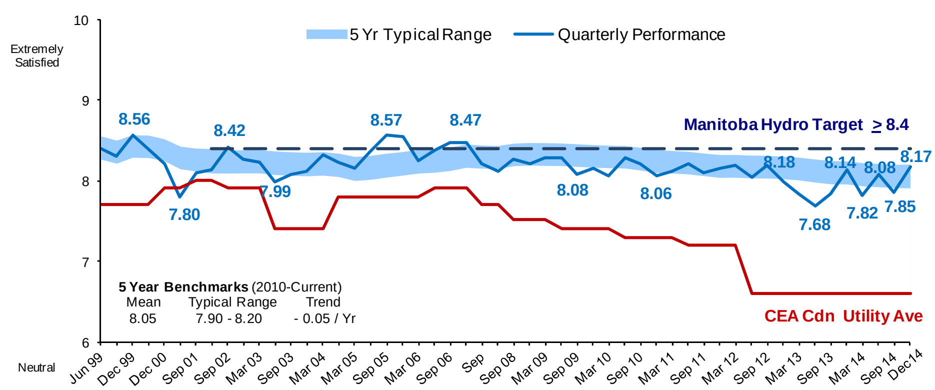
Manitoba Hydro
Customer Satisfaction Tracking Study, 2014/15 – 3rd Quarter "Topline" Report

This "Topline" reports the high level results from the Manitoba Hydro Customer Satisfaction Tracking Study (CSTS) fielded at the end of the 2014/15 fiscal year's third quarter from January 29 to February 1, 2015. A brief description of the study's history and methodology is provided at the end of this report.

OVERVIEW

Several key events during the October to December fall quarter likely influenced customer satisfaction with Manitoba Hydro's service including: Manitoba Hydro's response to various outages caused by early winter storms; a natural gas rate increase in November; and slightly warmer than average fall weather especially compared to the cold fall of 2013. As a result of these events and individual customer experiences, respondents continue to report they are relatively satisfied with the ***Overall Service*** they receive from Manitoba Hydro with 85% currently reporting a satisfaction score of 7 or higher on 10-point scale. Respondent satisfaction with Manitoba Hydro's *Overall Service* rose significantly during the third quarter of 2014-15 to 8.17 or just below the upper bound of its typical 5-year range of 7.90 to 8.20. Manitoba Hydro's performance continues to compare strongly to the CEA national average for Canadian electric utilities.

Customer Satisfaction with Overall Service



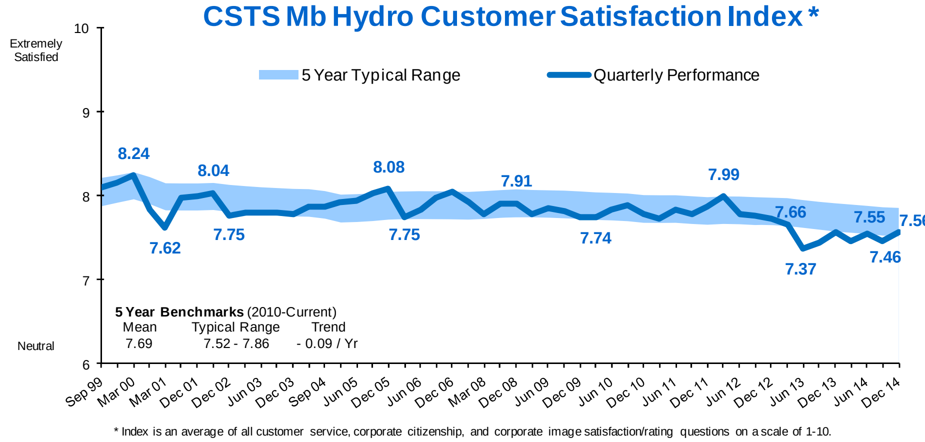
The proportion of respondents reporting a lower satisfaction score of 6 or less diminished from 19% last quarter to to more typical levels just below 13% this quarter. Those respondents reporting satisfaction scores of 6 or less for *Overall Service* this quarter cited high or rising prices (4% of all respondents), customer service problems (4%), or too many outages (2%) as the most common top-of-mind reasons. Less than 0.5% (2 or fewer respondents) mentioned local district office closures, being a monopoly, being poorly managed, or selling power abroad.

Respondent satisfaction with *Overall Service* in the third quarter is moderately correlated with *Power Reliability* and if respondents dealt with Manitoba Hydro staff during the past quarter, the *Overall Response* to that inquiry or service request and Manitoba Hydro's staff who responded to the inquiry or service requests being *Knowledgeable/Competent.* This suggests these elements had a stronger influence on satisfaction with *Overall Service* this past quarter.

During the past year, satisfaction with *Overall Service* has not varied in a significant and consistent manner between most respondent segments other than lower satisfaction levels being reported by respondents who are under 55 years of age, have electric only service or are Aboriginal. Third quarter results follow a similar pattern with slightly lower satisfaction levels reported by respondents who are: female (7.94 vs. 8.44 for male); middle aged (7.95 for 35-54 years vs. 8.40 for 13-35 years and 8.39 for 55+ years), have moderate education levels (7.95 for Some Post-Secondary vs. 8.21 for University Grads vs. 8.60 for High School or less); live in the Interlake (7.54) or Westman (7.85) service regions; have electric only service (7.95 vs. 8.25 for those with natural gas service), or are Aboriginal (7.73 vs. 8.27 for non-Aboriginal).

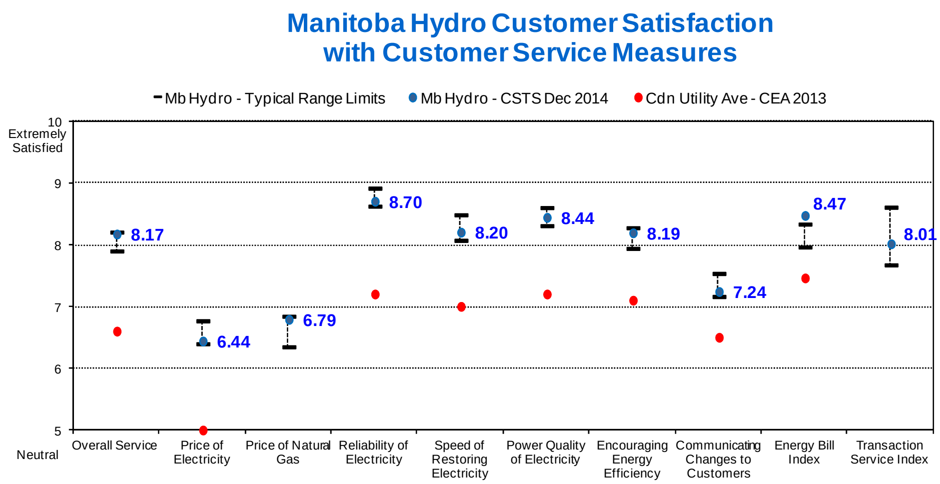
Taking a longer term view, after experiencing a significant downward 5-year trend (a 5-year trend is significant if ≥ ±0.05) between 2009 and 2013, satisfaction with *Overall Service* has begun to slowly recover since June 2013.

Manitoba Hydro's ***Customer Satisfaction Index*** *(CSI),* the average and broad directional indicator of respondent feedback regarding a number of measures, rose marginally during the October to December time period to just above the lower bound of its typical range. Manitoba Hydro's improved CSI performance this quarter reflects an increase in respondent satisfaction with almost all measures with nearly all measures now being within their typical 5-year range.



Manitoba Hydro's performance on all measures substantially exceeds the national average where there is a comparable electric utility national benchmark from the Canadian Electric Association (CEA)'s annual Public Attitude Research Project.

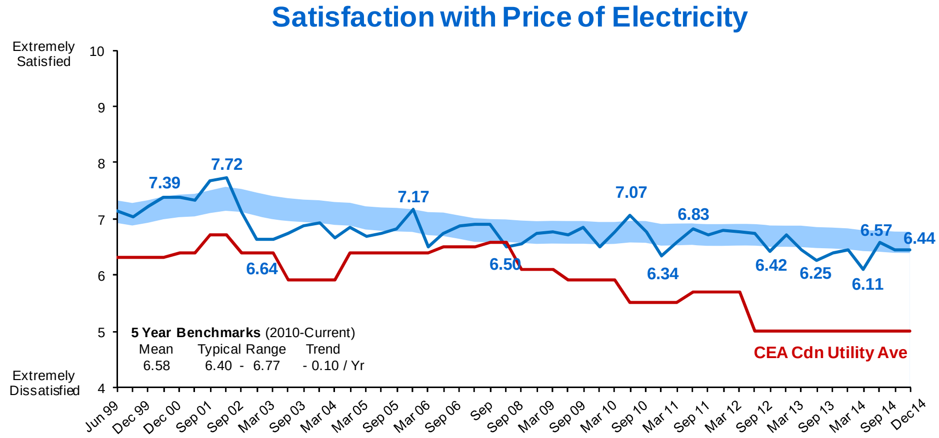
Customer satisfaction with eight of the ten ***Customer Service Measures*** rose during the third quarter - five rose significantly and three rose marginally. Satisfaction with the two other service measures remained unchanged (*Price of Electricity*) or declined marginally (*Reliability)*. As a result, satisfaction levels with all service measures are within or above (*Energy Bill Index*) their typical 5-year ranges.



Four service measures are experiencing moderately downward 5-year trends in satisfaction levels (*Price of Electricity, Speed of Restoring Power, Power Quality,* and *Communicating to Customers)*. Prior to the decline in June 2013, only two measures (*Overall Service, Communicating to Customers)* were experiencing downward 5-year trends, while two other measures (*Price of Natural Gas* and *Reliability*) were experiencing upward 5-year trends.

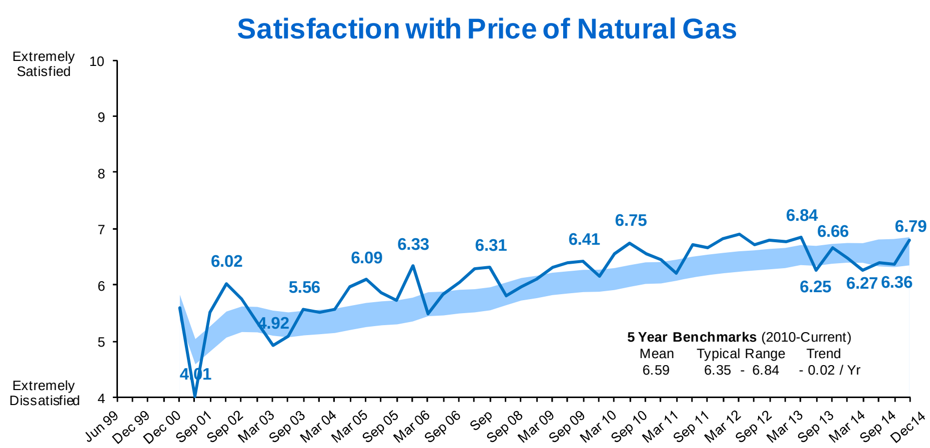
CUSTOMER SERVICE

Satisfaction with the ***Price of Electricity*** typically declines during the heating season (Oct-Dec, Jan-Mar) when heating bills are higher and recovers during the spring and summer quarters. It remained unchanged during the third quarter in the lower half of its typical range. It had previously been below its typical range for six of the seven quarters from September 2012 to March 2014 when it reached a historic low, but then recovered significantly by June 2014. The lower levels since 2012 were likely in response to electric rate increases, the publicity regarding future rate increases and the abnormally long and cold winter last year. Despite the recovery during the spring quarter, satisfaction with the *Price of Electricity* is still experiencing a significant downward 5-year trend. Nevertheless, it continues to exceed the 2013 CEA national average of 5.0. Currently, 52% of respondents report a satisfaction score of 7 or higher. Satisfaction levels do not vary significantly between most respondent segments, although lower satisfaction levels are reported by respondents who: live outside Winnipeg (6.08 vs. 6.80 for Winnipeg respondents) or are electric only customers (5.92 vs. 6.69 for gas customers). Higher satisfaction levels in Winnipeg are particularly notable in the Winnipeg Central service region (7.29) where there is a higher density of renters who typically report higher satisfaction levels (7.87 vs 6.24 for home owners).

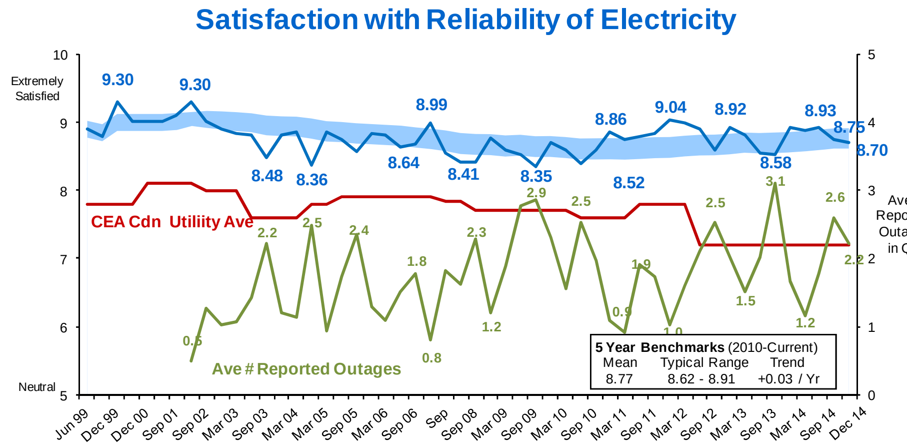


As has historically been the case, awareness levels in March of how Manitoba Hydro's electric rates compare to those in other provinces or states were moderate with 39% of respondents answering they "Do Not Know" how they compare. In March, while 31% believed Manitoba's electricity rates are lower, only 6% said Manitoba's electricity rates were much lower. Another 18% thought they are the same and 13% thought Manitoba's rates are higher. However, respondents also believed Manitoba electricity rates are rising at the same (30%) or faster (22%) rate than in other provinces or states. Only 10% thought Manitoba electricity rates are rising slow.

Satisfaction with the ***Price of Natural Gas*** also typically declines during the heating season (Oct-Dec, Jan-Mar) when heating bills are higher and recovers during the spring and summer quarters. Although natural gas rates rose in November by approximately 5% for a typical household, this seems to have been more than offset by the slightly warmer than average fall weather (especially compared to cold fall of 2013) and as a result, satisfaction with the *Price of Natural Gas* rose significantly during the third quarter to the upper half of its typical range at 6.79. Satisfaction levels trended upwards for most of the decade from 2003 to 2013, but fell back significantly in June 2013 and during last winter when both rates and consumption increased significantly. At the end of the third quarter, 56% of respondents report a satisfaction score of 7 or higher with this measure. Satisfaction does not vary significantly between most respondent segments, although lower satisfaction levels are reported by respondents who: have moderate education levels (6.29 for Some Post-Secondary vs. 7.04 for University Grads vs. 7.28 for High School or less), and respondents who live outside of Winnipeg (6.00 vs. 7.00 for those living in Winnipeg).



Satisfaction with the ***Reliability of Electricity*** continues to receive the highest average satisfaction score of any service component with nearly all respondents (90%) currently reporting a satisfaction rating of 7 or higher. It is moderately correlated with satisfaction with *Overall Service* this quarter suggesting it had a strong influence on satisfaction with *Overall Service* this past quarter. Satisfaction with the ***Reliability of Electricity*** declined marginally during the third quarter to 8.70 which is below its 5-year seasonal average for the fall quarter of 8.89.

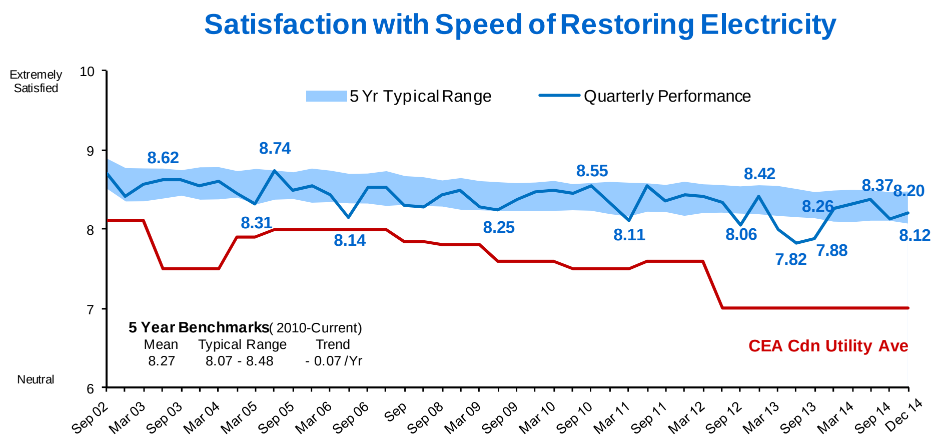


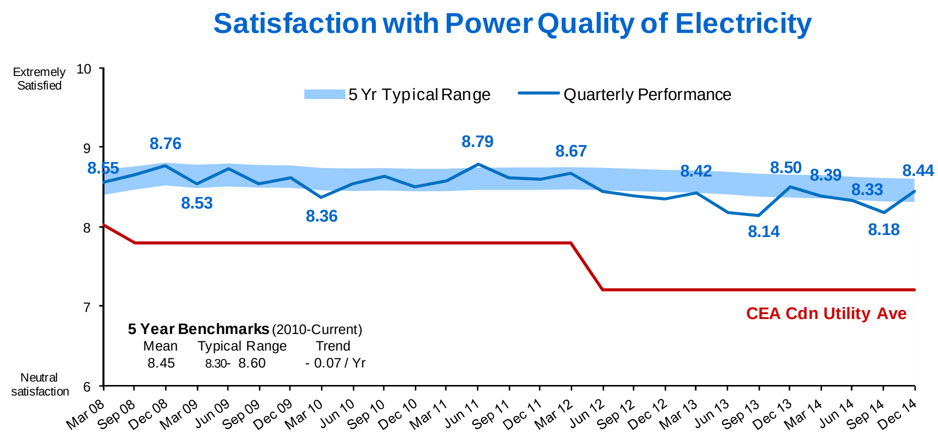
The slight decline in satisfaction rather than typical seasonal increase likely reflects the increase in the number of power outages during the October to December fall quarter reported by respondents (shown by line graph in bottom portion of *Reliability of Electricity* chart) and the duration of those outages. Across the province, 63% of respondents report experiencing an outage during the quarter (above the 5-year seasonal average of 56%) with respondents reporting an average of 2.21 outages (above the 5-year seasonal average of 1.60 outages) and the average longest outage experienced being 1.82 hours (on par with the seasonal average of 1.80).

Lower satisfaction levels were reported by respondents who live outside of Winnipeg (8.45 vs. 8.94 for Winnipeg) and particularly in the Interlake (8.13) and Westman (8.38) service regions from where respondents reported above average number of outages during the quarter (Interlake 3.69, Westman 4.13) and in the case of the Westman, a more lengthy longest outage duration of 5.64 hours. Of respondents living outside Winnipeg, those living in the North service region were the exception, reporting above average satisfaction with *Reliability of* Electricity (9.13) and a below average number of outages (1.10 outages).

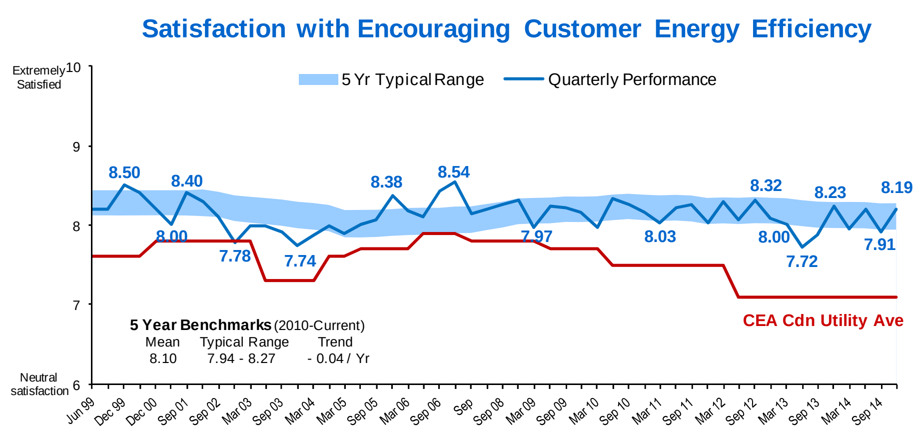
Consistent with results from the previous year, satisfaction with *Reliability of Electricity* at the end of the third quarter does not vary in a significant and consistent manner between most other market segments other than lower satisfaction levels being reported by respondents who are: middle aged (8.58 for 35-54 years vs. 8.68 for 18-35 years and 8.96 for 55+ years), have Some Post-Secondary education (8.29 vs. 8.92 for High School or less vs. 9.09 for University Grads), or are Aboriginal (7.99 vs. 8.82 for non-Aboriginal).

Satisfaction with Manitoba Hydro's ***Speed of Restoring Electricity*** after an outage rose marginally during the third quarter to 8.20 and just below its 5-year average. Although satisfaction with this measure has experienced a slow but significant downward 5-year trend, it appears have levelled off in mid-2013 and started to recover since. Manitoba Hydro's performance continues to exceed the CEA national average of 7.0. Currently, of respondents who experienced an outage during the quarter, 87% report a satisfaction score of 7 or higher with the *Speed of Restoring Electricity.* Satisfaction levels are relatively consistent between respondent segments although lower levels are reported by respondents who are middle aged (8.02 for 35-54 years vs. 8.40 for <35 years vs. 8.42 for 55+ years), have moderate levels of education (7.85 for Some Post-Secondary vs. 8.38 for University Grads), have higher family incomes (7.79 for $100,000+ vs. 8.22 <$60,000 vs. 8.89 for $60-100,000) or live in the Interlake (7.43), Winnipeg West (8.07) or to a lesser degree, the Westman (8.18) service regions.

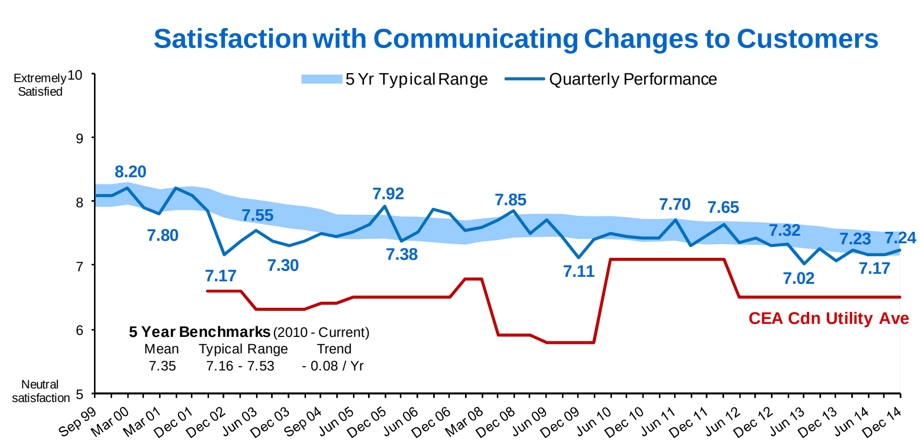




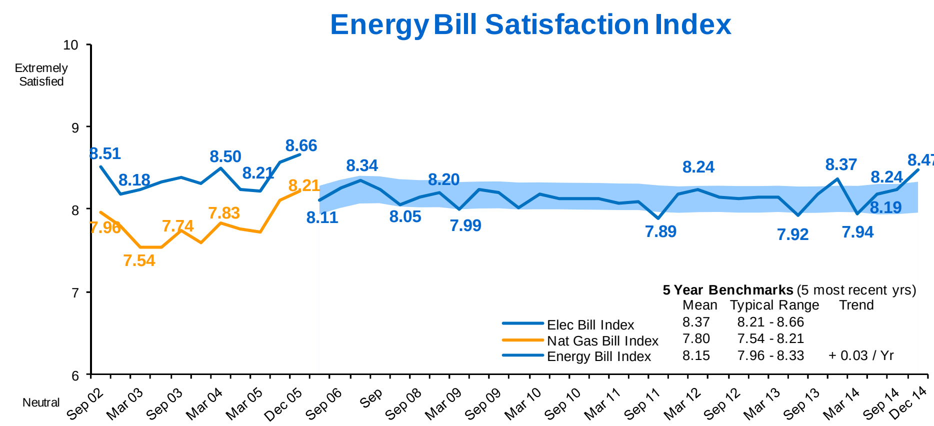
Power Quality of Electricity provided by Manitoba Hydro typically receives the second highest average satisfaction score of any service component. It recovered strongly during the third quarter from its decline in the prior two quarters (April to September) to 8.44 which is on par with its 5-year average. Although satisfaction with this measure continues to experience a slow but significant downward 5-year trend, it appears to be levelling off during the last two years. Manitoba Hydro's score continues to easily exceed the CEA 2013 national average of 7.2, and nearly all respondents (89%) report a satisfaction score of 7 or higher on this measure. Satisfaction levels are lower among respondents who are female (8.29 vs. 8.71 for male), middle aged (8.02 for 35-54 years vs. 8.68 for 55+ years vs. 8.73 for 18-34 years), have moderate education levels (7.97 for Some Post-Secondary vs. 8.73 for University Graduates vs. 8.80 for High School or less), earn higher family incomes (8.19 for $100,000+ vs. 8.43 for <$60,000 vs. 8.82 for $60-100,000), or live outside Winnipeg (8.18 vs. 8.69 for Winnipeg respondents) particularly in the Westman (7.52) or Interlake (7.71) service regions. Higher satisfaction levels are reported by respondents in the Winnipeg Central (9.20) or Interlake (9.03) service regions.

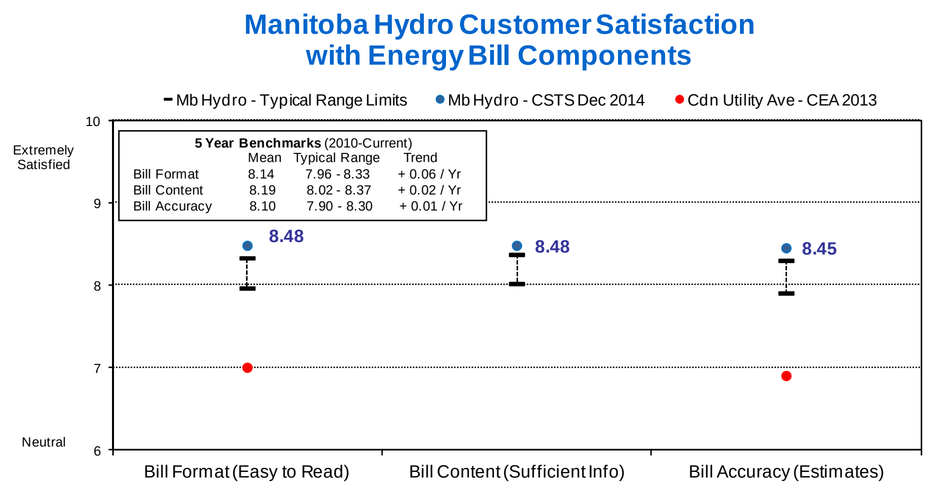


Satisfaction with ***Encouraging Energy Efficiency*** continued its variable behaviour and rose back significantly during the third quarter to 8.19 and the upper half of its typical 5-year range. Manitoba Hydro's performance continues to easily exceed the CEA 2013 national average of 7.1. At the end of the third quarter, 81% of respondents report a satisfaction score of 7 or higher for this measure. During the past year, satisfaction levels have not varied between most respondent segments in a significant and consistent manner other than lower satisfaction being reported by respondents who are male or are middle aged (35-54 years of age). Similarly, third quarter results were relatively constant between most customer segments with lower satisfaction levels reported by respondents who are: middle aged (7.84 for 35-54 years vs. 8.16 for 55+ years vs. 8.90 for 18-35 years), have Some Post-Secondary education (7.94 vs. 8.20 for University Grads vs. 8.68 for High School or less), or have family incomes of $100,000+ (7.97 vs. 8.15 for <$60,000 vs. 8.75 for $60-100,000).



Manitoba Hydro's efforts ***Communicating Changes to Customers*** usually receives the lowest satisfaction score of the customer service measures other than price. Satisfaction levels rose marginally during the third quarter to 7.24 or the lower half of the measure's typical range. Although satisfaction levels with this measure have been undergoing a slow, but significant downward 5-year trend since 2009 (scores have fallen near or below the lower bound of its typical range in fourteen of the last 15 quarters), it appears to be levelling off since late 2013. Despite the decline, Manitoba Hydro's performance remains above the CEA 2013 national average of 6.5. Two thirds (68%) of respondents report a satisfaction score of 7 or higher with Manitoba Hydro's performance on this measure. Consistent with results from the previous year, satisfaction with *Communicating Changes to Customers* at the end of the third quarter was lower among respondents who: are male (6.80 vs. 7.62 for females) or middle aged (6.88 for 35-54 years vs. 7.46 for 55+ years vs. 7.50 for <35 years). In contrast to the typical pattern, Aboriginal respondents did not report lower satisfaction levels this quarter (7.39 vs. 7.26 for non-aboriginal).





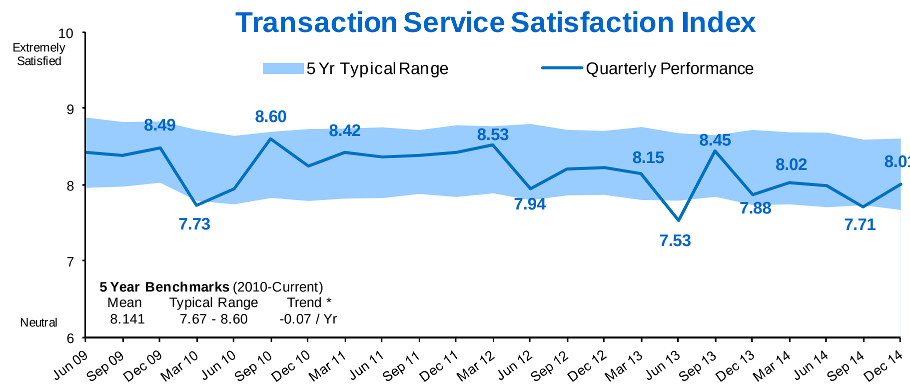
The ***Energy Bill Satisfaction Index*** is an average of three satisfaction measures regarding Manitoba Hydro's energy bill: *Bill Format* (easy to read and understand), *Bill Content* (provides sufficient information), and *Bill Accuracy.* The Index which has been relatively stable over the past decade rose significantly during the third quarter to above its typical 5-year range at 8.47.

The Index's rise during the quarter reflects a significant increase in satisfaction with *Bill Accuracy to* above its 5-year typical range as well as marginal increases in satisfaction with both *Bill Format* and *Bill Content* to above each of their respective 5-year typical ranges as well. The more typical winter weather this year and the resulting more typical energy bills are likely key contributors to the higher satisfaction with energy bills, particularly the accuracy of those bills. Where comparable CEA national data exists, Manitoba Hydro's performance significantly exceeds the national average. At the end of the third quarter, 89% and 90% of respondents report a satisfaction level of 7 or higher for *Bill Format* and *Bill Content* respectively, while 86% report a satisfaction level of 7 or higher with *Bill Accuracy.*

Satisfaction scores for these three measures varied in a fairly consistently pattern among customer segments with lower satisfaction levels tending to be reported by those who: are middle aged, have Post-Secondary or higher education levels, or earn family incomes of $100,000+.

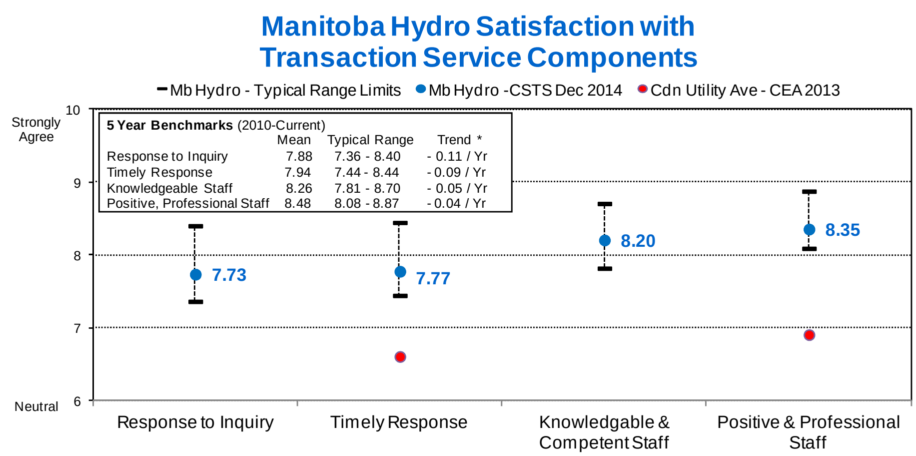
The ***Transaction Service Satisfaction Index*** is an average of four satisfaction measures regarding Manitoba Hydro's response to customer inquiries or service requests. A fifth (19%) of respondents said they dealt with Manitoba Hydro staff during the past quarter with the primary purposes being: Outages or Repairs (7%); Bills or Payments (5%); Services such as Call before You Dig, permits, service connects, Power Smart programs (4%), and Reporting or disputing meter reads (2%) . The vast majority of those who contacted Manitoba Hydro said they did so by phone (91%), while 5% spoke to staff in-person, and 2% contacted Manitoba Hydro by e-mail or social media. Others contacted Manitoba Hydro through a contractor (1%) or by fax (1%).

After behaving more erratically between June and December 2013, the *Transaction Service Satisfaction Index* has returned to a more stable pattern and remained relatively unchanged since. It recovered marginally during the third quarter to 8.01 from its dip in the second quarter, and is now on par with its 5-year average (due to the smaller sample of respondents who report contacting Manitoba Hydro each quarter, the transaction measures are less sensitive with a quarterly change only being statistically significant if it is ±0.6). Despite the fluctuations in 2013, the Index has remained relatively stable during the past 5-years (a 5-year trend is significant if ±0.12 or greater).



* Due to the smaller sample of respondents who report contacting Manitoba Hydro each quarter (N<100) , the transaction measures are less sensitive with a 5-year trend only being statistically significant if it is ±0.12).

The Index's marginal improvement during the third quarter reflects similar marginal improvements in satisfaction with three of the four transaction components during the quarter. As a result, satisfaction levels with these three components are now in the lower half of their 5-year typical range with 70% reporting a score of 7 or higher with ***Response to the Inquiry,*** 81% reporting a score of 7 or higher with both ***Timeliness of the Response*** and Manitoba Hydro's ***Knowledgeable and Competent Staff***. Satisfaction with the fourth measure, ***Positive & Professional Staff***, remained unchanged at 8.35 with 79% reporting a score of 7 or higher. Satisfaction scores for these four measures did not vary significantly between customer segments.



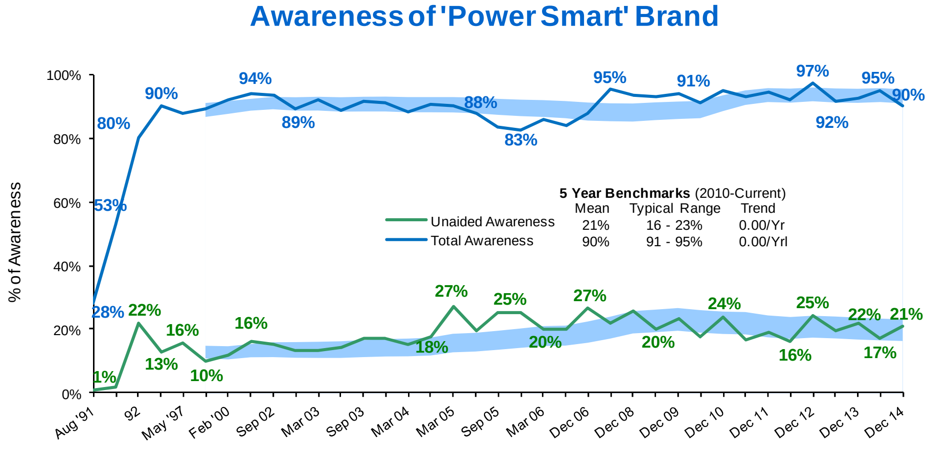
* Due to the smaller sample of respondents who report contacting Manitoba Hydro each quarter (N<100) , the transaction measures are less sensitive with a 5-year trend only being statistically significant if it is ±0.12).

Similar to previous quarters, satisfaction with *Overall Service* to customers is moderately correlated with Manitoba Hydro's *Knowledgeable/Competent Staff* and *Positive/Professional Staff* who respond to the inquiry or service requests suggesting that among those customers who contact Manitoba Hydro for inquiries or service requests, satisfaction with Manitoba Hydro's response has a strong influence on satisfaction with *Overall Service.*

Where comparable CEA national data exists, Manitoba Hydro's performance significantly exceeds the national average. Satisfaction levels are relatively consistent between customer segments.

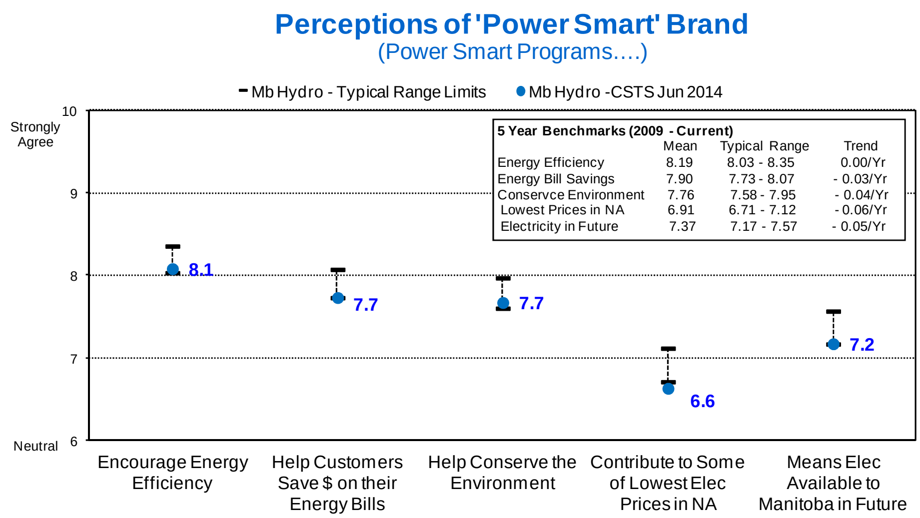
POWER SMART* AWARENESS AND PERCEPTIONS

POWER SMART is the brand name Manitoba Hydro has used since 1991 to promote its energy efficiency programs and services. Manitoba Hydro continues to maintain an exceptionally strong ***Awareness of the POWER SMART Brand*** in the Manitoba market with 90% of respondents saying they recognize the POWER SMART brand name. This includes 21% of respondents who independently recall the POWER SMART brand name (unaided awareness), and 69% of respondents who say they recognize the brand name after the POWER SMART name is stated (aided awareness). Awareness of the Power Smart brand remains very high among all customer segments although consistent with recent prior results, awareness levels at the end of the third quarter are slightly lower among respondents who: are not 35-54 years of age (84% of <35 years vs. 90% of 55+ years vs. 98% of 35-54 years), earn lower family incomes (83% of <$60,000 vs. 95% of $60,000+), rent their homes (82% of rent vs. 92% of own), live outside of Winnipeg (88% of those outside of Winnipeg vs. 92% of those living in Winnipeg) and particularly in the North (83%), or electric only customers (89% vs. 94% for those with both natural gas & electric services). In contrast to the typical pattern Aboriginal respondents report higher awareness levels (98% vs. 90% of non-aboriginal) at the end of the third quarter.



Approximately a third (36%) of respondents said they have participated in a Manitoba Hydro POWER SMART program in the past. This is fairly consistent across most customer segments although respondents are less likely to have participated in a POWER SMART*program if they have lower education levels (20% of HS or less vs. 45% of Some Post-Secondary vs. 39% of University Grads), have lower family incomes (24% for <$60,000 vs. 39% of $60-100,000 vs. 44% of $100,000+), rent their home (4% vs 42% of those who own), live outside of Winnipeg (33% vs. 40% of those in Winnipeg) particularly in the North service region (22%), are Aboriginal (29% vs. 38% non-aboriginal) or are electric only households (29% vs 44% of natural gas/electric customers).

In June 2014, respondents who said they are aware of the POWER SMART brand were asked to indicate their level of agreement with several statements regarding POWER SMART on a 10-point scale, where 10 is strongly agree. In general, the strength of respondent agreement with all the statements has begun to decline with most now near the lower bound of their typical ranges. Respondents continue to strongly agree that POWER SMART ***Encourages Customers to be more Energy Efficient*** (8.1, 80% reported 7 or higher), ***Helps Customers Save Money on their Energy Bills*** (7.7, 74% reported 7 or higher) and, ***Helps Conserve the Environment*** (7.7, 72% reported 7 or higher). However, agreement that POWER SMART ***Means Electricity will be Available to Manitobans in the Future*** (7.2, 62% reported 7 or higher) and



Contributes to Manitobans paying among the Lowest Electricity Prices in North America (6.6, 49% reported 7 or higher) have both been slowly but significantly declining during the past 5 years and both dropped significantly further since the end of December 2013. This may be the result of other conflicting messages being received from recent communication campaigns that suggest demand for electricity is growing to the point that additional generation will soon be required and that electric prices are and will be rising further to invest in these and other infrastructure renewal upgrades. Perceptions are relatively consistent between customer segments although there was slightly less agreement with the statements by respondents who are male or are non-Aboriginal.

Manitoba Hydro Customer Satisfaction Tracking Study, Quarterly Results Scorecard, 2014/15 – 3rd Qtr (Dec 2014)

Measure	Current Quarter Ave&Chg	Within Typical Range	5 Year Trend	Exceeds CEA Ave.	Current Quarter Rated 7-10
Overall Service	↑ 8.17	✓ **(7.90-8.20)**	↓	✓ **(6.6)**	85%
Price of Electricity	6.44	✓ **(6.40-6.77)**	↓	✓ **(5.0)**	52%
Price of Natural Gas	↑ 6.79	✓ **(6.35-6.84)**	-	NA	56%
Reliability of Electricity	8.70	✓ **(8.62-8.91)**	-	✓ **(7.2)**	90%
Speed of Restoring Electricity	8.20	✓ **(8.07-8.48)**	↓	✓ **(7.0)**	87%
Power Quality of Electricity	↑ 8.44	✓ **(8.30-8.60)**	↓	✓ **(7.2)**	89%
Encouraging Customer Energy Efficiency	↑ 8.19	✓ **(7.94-8.27)**	-	✓ **(7.1)**	81%
Communicating Changes to Customer	7.24	✓ **(7.16-7.53)**	↓	✓ **(6.5)**	68%
Bill Index	↑ 8.47	★ **(7.96-8.33)**	-	NA	89%
Bill Format	8.48	★ **(7.96-8.33)**	↑	✓ **(7.0)**	89%
Bill Content	8.48	★ **(8.02-8.37)**	-	NA	90%
Bill Accuracy	↑ 8.45	★ **(7.90-8.30)**	-	✓ **(6.9)**	86%
Transaction Service Index	8.01	✓ **(7.67-8.60)**	-	NA	78%
Response to Inquiry	7.73	✓ **(7.36-8.40)**	-	NA	70%
Timely Response	7.77	✓ **(7.44-8.44)**	-	✓ **(6.6)**	81%
Knowledgeable & Competent Staff	8.20	✓ **(7.81-8.70)**	-	NA	81%
Professional& Positive Staff	8.35	✓ **(8.08-8.87)**	-	✓ **(6.9)**	79%

STUDY HISTORY AND METHODOLOGY

This report is based on 500 randomly selected residential Manitoba households surveyed January 29-February 1, 2015. Overall results are accurate ±4.4%, 19 times out of 20. Manitoba Hydro established the Customer Satisfaction Tracking Study in June 1999 to track customer perceptions of its customer service, corporate citizenship and corporate image. For further information, please contact Grant Meder, Power Smart Planning, Evaluation and Research.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain precisely how the survey determines “customer satisfaction”.

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the “best in Canada”. However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

Customer satisfaction is determined using the average satisfaction score reported by respondents to the following question in the Customer Satisfaction Tracking Study (CSTS):

> *“I would now like to ask you about your level of satisfaction with the overall service Manitoba Hydro provides its customers. On a scale of 1 to 10, where 1 is extremely dissatisfied and 10 is extremely satisfied, how satisfied are you with the overall service you have received from Manitoba Hydro?”*

This measure, *Satisfaction with Overall Service*, provides a broad measure of customer satisfaction with Manitoba Hydro’s service, allowing respondents to take into consideration any factors/events they consider important in assessing how Manitoba Hydro's service compares to their expectations.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
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PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a full copy of the most recent survey's results.

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-6c.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

What is the basis for the >8.4/10 target in the current CSP?

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

The target was originally set in the creation of the 2001 Corporate Strategic Plan when satisfaction levels with Manitoba Hydro's overall service were typically varying from 8.1 to 8.4 (95% confidence interval). A metric of >8.4 was considered a reasonable stretch target.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on the most recent CEA results, how does Manitoba Hydro compare with other Canadian utilities in terms of the CEA Customer Service Index?

RATIONALE FOR QUESTION:

The 2011/12 CSP (filed in the last GRA) used the CEA Customer Service Index as a measure of customer value with a target to be the "best in Canada". However, the current CSP uses a different measure for customer satisfaction.

CSP targets are one measure of prudence of expenditures. The questions posed seek additional detail as compared to analogous ones from GAC and the MMF.

RESPONSE:

Manitoba Hydro's understanding is that the Coalition has clarified it is requesting a comparison of Manitoba Hydro's Customer Service Index to the average of other Canadian utilities based on information collected from the CEA.

The CEA Canadian Utility Average for Customer Satisfaction with Overall Service was provided for the period from June 1999 –September 2014 in Figure 2.4 of Tab 2 of the Application, and has been updated to December 2014 in the Customer Satisfaction Tracking Study provided in response to Coalition/MH I-6c.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

The 2011 CSP (Appendix 3.1 from the last GRA) had a target for SAIDI of <90 minutes. In contrast, the target in the current CSP is <116 minutes. Please explain why the target has been set at a lower level (in terms of customer value) in the current CSP.

RATIONALE FOR QUESTION:

Manitoba Hydro has revised the reliability targets in its CSP. The targets are one measure of reasonablnness of expenditures.

RESPONSE:

The CSP performance target for outage duration (SAIDI) was revised from <90 minutes to <116 minutes in 2012 to provide a fairer assessment of Manitoba Hydro reliability performance relative to other utilities operating in similar environments and facing similar challenges, such as extreme weather and aging infrastructure. The revised target is intended to reflect the five year average of the top quartile of reliability performance of Canadian Electricity Association (CEA) utilities.

Manitoba Hydro's previous SAIDI target was established in 1999 and was based on a 5% improvement of the historical outage duration performance over the previous five years. In consideration of how SAIDI performance could deviate from year to year based on outages caused by storms or major equipment failures, it is believed that a target which considers the performance of electric utilities facing similar issues is a fairer threshold to strive for versus an independent assessment of its operations. As illustrated in Tab 2, Figure 2.5, Manitoba Hydro has consistently achieved performance within the top quartile of SAIDI CEA utility reporting utilities and continuing to comparatively perform in this range was considered a reasonable performance objective to provide reliable service to its customers.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Similarly the 2011 CSP had a target for SAIFI of <1.3 per year whereas the target in the current CSP is <1.4 per year. Again, please explain why the target has been set at a lower level (in terms of customer value).

RATIONALE FOR QUESTION:

Manitoba Hydro has revised the reliability targets in its CSP. The targets are one measure of reasonablnness of expenditures.

RESPONSE:

The CSP performance target for outage frequency (SAIFI) was revised from <1.3 outages per year to <1.4 outages per year in 2012 to provide a fairer assessment of Manitoba Hydro reliability performance relative to other utilities operating in similar environments and facing similar challenges, such as extreme weather and aging infrastructure. Similar to SAIDI, the revised target is intended to reflect the five year average of top quartile reliability performance of Canadian Electricity Association (CEA) utilities.

Similar to Manitoba Hydro's response to Coalition/MH I-7a, Manitoba Hydro's previous SAIFI target was established in 1999 and was based on a 5% improvement of the historical outage duration performance over the previous five years. In consideration of how SAIFI performance could also deviate from year to year based on outages caused by storms, tree to overhead line contact and numerous equipment failures, it is believed that a target that considers the performance of electric utilities facing similar issues is a fairer threshold to strive for versus an independent assessment of its operations. As illustrated in Tab 2, Figure 2.6, Manitoba Hydro has maintained performance within the top quartile of SAIFI CEA utility reporting utilities and continuing to comparatively perform in this range was considered a reasonable performance objective to provide reliable service to its customers.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain the "measure" used for electric energy DSM in the current CSP and how it differs from the measure used in the 2011 CSP (filed as Appendix 3.1 in the last GRA).

RATIONALE FOR QUESTION:

The 2011 CSP had a DSM – electric energy saved target of 1,939 GWh per year by March 2012. In contrast, the current CSP has an electric energy saved target of 363 GWh. Similarly, there is material difference in the target for electric capacity as between the two CSPs. The material differences in targets suggest there have been changes in the measures used. This goes to prudence of current plan.

RESPONSE:

The DSM energy target of 1,939 GW.h included in the 2011 CSP was the forecasted annual energy savings to be achieved by the end of 2011/12 including savings achieved to date.

The DSM energy target of 363 GW.h included in the current CSP is the forecasted annual energy savings to be achieved by the end of 2014/15 excluding savings achieved to date.

Section:	Tab 2: Appendix 2.1	**Page No.:**	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain the "measure" used for electric capacity DSM in the current CSP and how it differs from the measure used in the 2011 CSP.

RATIONALE FOR QUESTION:

The 2011 CSP had a DSM – electric energy saved target of 1,939 GWh per year by March 2012. In contrast, the current CSP has an electric energy saved target of 363 GWh. Similarly, there is material difference in the target for electric capacity as between the two CSPs. The material differences in targets suggest there have been changes in the measures used. This goes to prudence of current plan.

RESPONSE:

The DSM capacity target of 575 MW included in the 2011 CSP was the forecasted annual capacity savings to be achieved by the end of 2011/12 including savings achieved to date.

The DSM capacity target of 243 MW included in the current CSP is the forecasted annual capacity savings to be achieved by the end of 2014/15 excluding savings achieved to date.

Section:	Tab 2: Appendix 2.1	Page No.:	18
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain why the definitions/bases for the measures were changed.

RATIONALE FOR QUESTION:

The 2011 CSP had a DSM – electric energy saved target of 1,939 GWh per year by March 2012. In contrast, the current CSP has an electric energy saved target of 363 GWh. Similarly, there is material difference in the target for electric capacity as between the two CSPs. The material differences in targets suggest there have been changes in the measures used. This goes to prudence of current plan.

RESPONSE:

The current CSP uses energy and capacity targets excluding any savings achieved to date.

This measure of energy and capacity isolates the current fiscal year and provides a better representation of DSM energy and capacity savings achieved during the fiscal year.

Section:	Appendix 3.1 (from 2012/13 & 2013/14 GRA)	Page No.:	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

It is understood that the 2011 CSP was for the 2011/12 period.

QUESTION:

Please provide a schedule that set out the various measures and corresponding targets from the 2011 CSP and which also shows the actual results for the year (2011/12).

RATIONALE FOR QUESTION:

To assess Manitoba Hydro's performance relative to the targets set out in previous Corporate Strategic Plans. This is one measure of prudence.

RESPONSE:

Please see the attachment to this response.

Prepared for: Manitoba Hydro 2014/15 & 2015/16 General Rate Application
Round 1 IR - Coalition 9 a & b

Targets in 2011/12 CSP & Results for 2011/12, 2012/13, 2013/14

2011/12 CSP Goal	2011/12 CSP Measure	2011/12 CSP Target	Results as of: March 31, 2012	March 31, 2013	March 31, 2014
Improve safety in the workplace	Accident severity rate	< 16 days per 200 000 hours worked	10.18	9.7	11.1
	Accident frequency rate	< 0.80 accidents per 200 000 hours worked	0.91	0.7	0.7
	High risk incidents	0	2	0	0
Provide exceptional customer value	System average interruption duration	≤ 90 minutes	143	175	106
	System average interruption frequency	≤ 1.3 per year	1.67	1.89	1.26
	Canadian Electricity Association (CEA) Customer Service Index	Best in Canada	Best in Canada	Among Leading Utilites (Ranked 2nd)	Results not available yet from CEA
	Retail electricity rates	Lowest in North America	Among the lowest in North America	Lowest in North America	Among the lowest in Canada
	Retail natural gas distribution rates	Among the lowest in North America	3rd lowest amongst local distribution companies in major Canadian cities	Among the lowest in Canada	Among the lowest in Canada
Strengthen working relationships with Aboriginal peoples	Percentage of impacted Aboriginal communities with a workable management framework	100%	Measure under review	Measure not defined	Measure not defined
	Percentage Aboriginal employment - Corporate Overall - Northern - Management - Professional	 16% 45% 6% 8%	 15.7% 41.3% 4.6% 6.7%	 17% 41.8% 7.1% 7.3%	 17.6% 44.1% 7.1% 7.2%
Maintain financial strength	Debt/equity ratio	Maximum 75% debt ratio	74:26	75:25	76:24
	Interest Coverage Ratio	>1.2	1.10	1.15	1.28
	Capital Coverage Ratio	> 1.2 excluding major generation & transmission	1.13	1.25	1.35
	Operation, maintenance and administration (OM&A) cost per customer - electric	$739 per customer (March 2012)	$743	$844	$865
	OM&A cost per customer - gas	$238 per customer (March 2012)	$232	$236	$245
Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba	Percentage of non-entry positions filled by external applicants	Range 8%-12%	7.1	10.1	10.5
	Percentage of designated group members in Manitoba Hydro workforce - Women - Women in management - Women professionals - Persons with a disability - Visible minorities - Aboriginal	 26% 20% 35% 6% 6% 16%	 24.7% 20.3% 33.9% 4.7% 6.1% 15.7%	 24.8% 22.9% 33.8% 10.2% 7.3% 17.0%	 24.5% 22.4% 33.8% 9.9% 7.8% 17.6%
Protect the environment in everything that we do	Percent of electricity generated in Manitoba that is renewable	> 99%	99.9%	99.7%	99.6%
	Environmental component of CEA Customer Service Index	≥ 8.5	7.7	6.8	Results not available yet from CEA
	Corporate Citizenship Index - environmental component	≥ 8.4	7.47	7.44	7.28
	Greenhouse gas emissions	< 520 kilotonnes/yr (6% below 1990 levels)	157 kT (Calendar 2011)	149 kT (Calendar 2012)	163 kT (Calendar 2013)
	Maintain EMS ISO 14001 registration	Registration maintained	Registration maintained	Registration maintained	Registration maintained

2011/12 CSP Goal	2011/12 CSP Measure	2011/12 CSP Target	Results as of: March 31, 2012	March 31, 2013	March 31, 2014
Promote cost effective energy conservation and innovation	Demand side management (DSM) - electric energy saved	1 939 gigawatt-hours (GWh) per year by March 2012 3 408 GWh per year by 2024/25	1 966 GWh	2,269 GW.h	2,486 GW.h
	DSM - electric capacity saved (at winter peak)	575 megawatts (MW) by March 2012 918 MW by 2024/25	583 MW	637 MW	688 MW
	DSM - natural gas energy saved	61 million cubic metres per year by March 2012 149 million cubic metres per year by 2024/25	70 million cubic metres	84 million cubic metres	93 million cubic metres
Be recognized as an outstanding corporate citizen and a supporter of economic development in Manitoba	CEA Public Attitude Index	≥ 8.5	7.8	7.1	Results not available yet from CEA
	Manitoba Hydro Corporate Citizenship Index	≥ 8.2	7.65	7.6	7.5
	Public Contacts - natural gas & electric	20% injury reduction (reduction of average of previous 5 years = 15 injuries)	15	20	15
	Economic Development Agency satisfaction	100% satisfied	89%	Survey no longer conducted	Survey no longer conducted

Section:	Appendix 3.1 (from 2012/13 & 2013/14 GRA)	**Page No.:**	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets		

PREAMBLE TO IR (IF ANY):

It is understood that the 2011 CSP was for the 2011/12 period.

QUESTION:

In the same schedule please provide the actual results for each of the 2011 CSP measures for 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

To assess Manitoba Hydro's performance relative to the targets set out in previous Corporate Strategic Plans. This is one measure of prudence.

RESPONSE:

Please see the attachment to COALITION/MH-I-9a.

Section:	Recent NFAT Hearing: Attachment H (2012/13 CSP)	**Page No.:**	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets & Strategies		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro provided a copy of the 2012/13 Corporate Strategic Plan in the recent NFAT proceeding.

QUESTION:

Please provide a copy of the 2012/13 CSP for purposes of the record in this proceeding.

RATIONALE FOR QUESTION:

Assess Manitoba Hydro's performance relative to its 2012/13 Corporate Strategic Plan which serves as one measure of reasonableness of expenditure. Justifying O, M, & A costs is critical to the reasonableness of rates.

RESPONSE:

Please see attached.

Corporate Strategic Plan 2012-2013

Manitoba Hydro
PO Box 815 STN MAIN
Winnipeg, Manitoba
R3C 2P4

Phone: 204-360-3311
publicaffairs@hydro.mb.ca
www.hydro.mb.ca

Registered to: ISO 14001

Looking like pieces of a puzzle, this photo, courtesy of Mel Marcial (Keeyask Engineering & Construction) shows frazil ice formation at the tailrace channel of Wuskwatim Generating Station. Frazil ice is created when water movement interrupts ice crystal growth and the crystals don't join together to form a sheet.

Manitoba Hydro

Introduction
Vision
Goals
Safety
Customer Value
Aboriginal Relations
Financial Strength
Energy Markets
Workforce
Environment
Energy Conservation & Innovation
Corporate Citizen

Introduction

The Corporate Strategic Plan (CSP) reflects Manitoba Hydro's vision, mission and goals. The CSP is reviewed annually by our Executive management team and the Manitoba Hydro-Electric Board and demonstrates our ongoing commitment to maintaining reliable and affordable energy while planning for long-term financial sustainability.

In all the work that we do, safety is our number one priority. A focus on continuous safety improvements has resulted in a steady decline in workplace accident severity and frequency rates, a trend we will strive to continue.

As we expand our capacity to meet the energy requirements within Manitoba and pursue export opportunities, we continue to engage our stakeholders, in particular Aboriginal and rural communities in which we operate. Our planned investments are significant over the next decade, both in new generation development and the modernization of our existing infrastructure. These investments, along with our ongoing operations, will contribute to the growth of the Manitoba economy and will have a lasting positive impact for future generations.

Scott A.Thomson, CA
President & CEO

Vision

To be the best utility in North America with respect to safety, rates, reliability, customer satisfaction, and environmental leadership, and to always be considerate of the needs of customers, employees, and stakeholders.

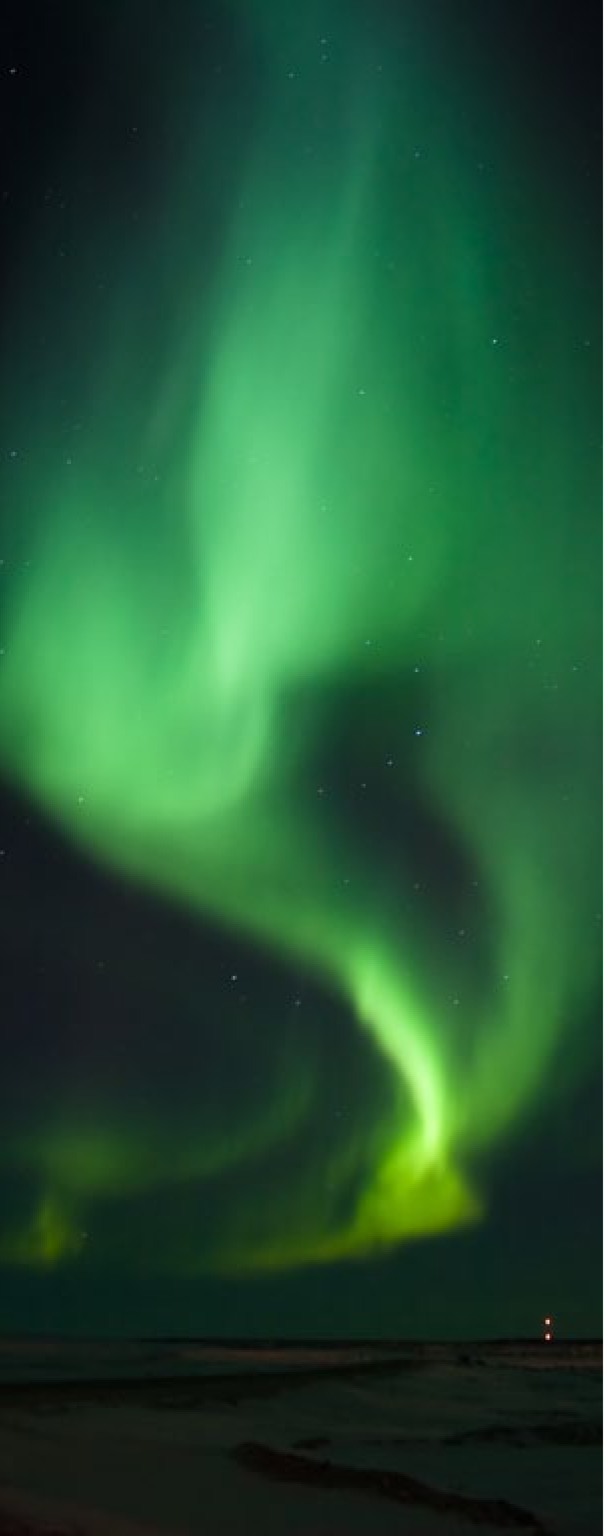
Mission

To provide for the continuance of a supply of energy to meet the needs of the province and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy.

Operating Principles

- Work together for the success of the organization as a whole, recognizing that all our activities are interrelated.
- Establish long-term cooperative relationships with all employees, customers, suppliers, and other stakeholders, aimed at achieving our shared Vision.
- Create a working environment that removes barriers to effective performance and which fosters mutual respect, trust and open communication.
- Promote a safety focused culture in which all employees support and demonstrate safe work behaviours.
- Provide opportunities for all employees to develop their full potential, recognizing people's inherent desire to do their best.
- Measure outcomes, develop an understanding of the causes of variation from planned performance and take appropriate action.
- Practice continuous improvements through ongoing coaching, learning and innovation, focused on the needs and wants of internal and external customers.

Gordon Ross (Community Relations) always has his camera with him. Heading out his front door to work one morning, he stopped to take this shot of the sunrise in Cross Lake.



Goals

Improve safety in the workplace.	Safety
Provide exceptional customer value.	Customer Value
Strengthen working relationships with Aboriginal peoples.	Aboriginal Relations
Maintain financial strength.	Financial Strength
Extend and protect access to North American energy markets and profitable export sales.	Energy Markets
Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba.	Workforce
Protect the environment in everything that we do.	Environment
Promote cost effective energy conservation and innovation.	Energy Conservation & Innovation
Be recognized as an outstanding corporate citizen and a driver of economic development in Manitoba.	Corporate Citizen

While working in Churchill, Adam Sawchuk (Keeyask Engineering & Construction) took a quick drive down to the coast on a clear -40 degree night and captured the Northern Lights.

Improve safety in the workplace

Strategies

- Instill safety culture in all corporate activities.
- Reinforce management, supervisory and worker accountability for a safe and healthy workplace.
- Implement safety reporting protocols that incorporate thorough investigation and timely communication of all safety-related incidents.
- Design and implement safe driving programs that address the need to substantially reduce the number of driving incidents.

Measure	Accident severity rate	Accident frequency rate	High risk incidents
Challenge	< 12 days per 200 000 hours worked	< 0.60 accidents per 200 000 hours worked	0

During training, at the Lineman's Rodeo or in the field, Hydro crews know that creating a job plan is imperative. Not only do they include an emergency response plan, but they also identify the major hazards in the job steps and list ways to control or eliminate those hazards.

Provide exceptional customer value

Strategies

- Maintain high system reliability, reasonable rates and excellent customer service.
- Continue to assist customers in making informed decisions regarding the use of natural gas and electricity.
- Continue to evaluate the full range of options to meet Manitoba load and reliability requirements.
- Implement distribution automation as part of a cost effective Smart Grid strategy.
- Explore opportunities for natural gas supply and storage.
- Evaluate the impacts of low gas prices for a potentially sustained period.
- Maintain compliance with applicable North American Electric Reliability Corporation (NERC) reliability standards and foster a culture of reliability excellence.

Measure	System average interruption duration	System average interruption frequency	CEA* Customer Service Index	Retail electricity rates (overall)	Retail natural gas distribution rates
Target	< 113 minutes which represents the best performing utility in the CEA* (5 year average)	< 1.4 outages which represents the best performing utility in the CEA* (5 year average)	Best in Canada	Lowest in North America	Among the lowest in Canada

* *Canadian Electricity Association*

Recently launched technology called Mobile Workforce Management is changing how Customer Service Operations fieldwork activities are administered and dispatched. It will improve workload and workplace distribution, enhance customer safety and satisfaction, advance forecasting and planning as well as increasing productivity.

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Strengthen working relationships with Aboriginal peoples

Strategies

- Ensure impacted Aboriginal communities have a workable management framework.
- Continue to address the effects of Manitoba Hydro's operations on Aboriginal communities.
- Develop and maintain business relationships with Aboriginal companies.
- Continue initiatives to recruit, develop and retain Aboriginal employees.

Percentage Aboriginal employment

	Corporate overall	Northern	Management	Professional
Measure	Corporate overall	Northern	Management	Professional
Target	16%	45%	6%	8%

Left to right, Joe Halcrow and Joseph McKay (both Boat Patrol) patrol the waterways along the Nelson River for safety hazards. They remove debris and look for boaters in need of assistance; as well, they help to transport thousands of sturgeon eggs destined for the Grand Rapids Fish Hatchery to help build the sturgeon population in Manitoba.

Maintain financial strength

Strategies

- Ensure that the achievement of financial targets is considered in all major corporate decisions.
- Continue to implement asset investment planning projects.
- Implement and track sustainable initiatives to ensure that OM&A costs are fully justified.
- Demonstrate to stakeholders that regular reasonable rate increases are necessary for future price stability.
- Obtain and renew the licenses that Manitoba Hydro requires to sustain its business.
- Explore opportunities to further optimize the benefits of the natural gas and electricity systems.
- Pursue opportunities to address increasing workloads associated with regulation and changing industry standards.

				Operation Maintenance and Administration (OM&A)	
Measure	Interest coverage	Debt/equity ratio	Capital financing ratio	Cost per customer – electric	Cost per customer – natural gas
Target	> 1.2	75:25	> 1.2 excluding major generation & transmission	$814*	$248

** Reflects accounting changes in 2012/13.*

Tim Loewen (Civil Engineering) took this shot inside the de-watered draft tube of Unit 6 at Kelsey Generating Station. As part of the re-runnering project, concrete is being placed to improve flow.

Extend and protect access to North American energy markets and profitable export sales

Strategies

- Pursue a balanced portfolio of export sales.
- Protect transmission rights and expand transmission capacity to support access for exports and imports.
- Participate in national and international forums to facilitate exports.
- Promote new hydro and transmission as part of the solution to climate change.
- Participate in the development of regulatory and industry frameworks for electricity, including renewable energy standards.
- Advance in-service dates of new hydro facilities, where economic, to take advantage of export opportunities.
- Ensure that plans are robust enough to withstand a range of alternative scenarios.

Transmission interconnections provide greater access to the U.S. market where our customers are looking for cleaner energy. As well, the province benefits from enhanced reliability and access to additional energy when drought impacts Manitoba hydraulic generation.

Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba

Strategies

- Continue to promote Manitoba Hydro as an employer of choice.
- Provide a work environment that allows employees to have a balanced approach to family, work and community.
- Continue to implement programs to enhance employee technical, leadership and business skills.
- Implement solutions to address current and future skill shortages.

Measure	Percentage of non-entry positions filled by external applicants
Target	Range 8%–12%

Percentage of designated group members in Manitoba Hydro workforce

Measure	Women	Women in management	Women professionals	Women in trades
Target	26%	20%	35%	4%
Measure	Persons with a disability	Visible minorities	Visible minorities in management	Aboriginal
Target	6%	7%	3%	16%

Carole Kouessi (Electrical Engineering) is a new immigrant and is part of the Engineer-in-Training program at Manitoba Hydro. She appreciates that employees are able to broaden their skills and competencies with a variety of internal and external training as well as through rotational training programs.

Protect the environment in everything that we do

Strategies

- Instill a culture of environmental awareness and the interaction between the corporation's activities and the environment.
- Prevent or mitigate adverse environmental impacts of Manitoba Hydro's activities.
- Conduct or support environmental research, monitoring and educational programs relevant to sustainable development and Manitoba Hydro's operations.
- Maintain and improve Manitoba Hydro's Environmental Management System including ISO 14001 registration.
- Participate in the development of evolving environmental regulations and climate change policies.
- Enhance public understanding of how Manitoba Hydro's hydroelectricity exports displace greenhouse gas emissions in other regions.
- Expand green procurement, green fleet and other potential opportunities.

Measure	Percent of electricity generated in Manitoba that is renewable	Greenhouse gas emissions
Target	> 99%	< 520 kilotonnes per year (6% below 1990 levels)

In planning our projects, Manitoba Hydro examines and mitigates impacts on surrounding habitat.

Promote cost effective energy conservation and innovation

Strategies

- Aggressively develop, implement and promote Power Smart* programs.
- Use rate design and targeted price signals to encourage energy efficiency.
- Leverage information technology and R&D to support cost effective innovation.
- Encourage economically viable emerging energy options.

Demand Side Management

Measure	Electric energy saved	Electric capacity saved (at winter peak)	Natural gas energy saved
Target	2 069 gigawatt-hours per year by March 2013	612 megawatts by March 2013	82 million cubic metres per year by March 2013
	3 283 gigawatt-hours per year by 2025/26	906 megawatts by 2025/26	153 million cubic metres per year by 2025/26

The Power Smart Refrigerator Retirement Program aims to remove 35,000 old, inefficient fridges from homes over 2.5 years. This will reduce energy consumption by approximately 30 gigawatt hours — equivalent to the amount of electricity required to power the Town of Neepawa for a year.

** Manitoba Hydro is a licensee of the Trademark and Official Mark.*

Be recognized as an outstanding corporate citizen and a driver of economic development in Manitoba

Strategies

- Effectively communicate the benefits Manitoba Hydro delivers to Manitobans.
- Support staff participation in community activities.
- Deliver effective public education and safety programs.
- Take proactive steps to enhance external communications and image.
- Facilitate economic development opportunities for Manitoba.
- Broaden employee knowledge to create ambassadors for Manitoba Hydro.
- Engage with stakeholders, including the public at large, to understand their interests.

Measure	CEA Corporate Citizenship Index	Manitoba Hydro Corporate Citizenship Index	Public Contacts – natural gas & electric
Target	≥ 8.5	≥ 8.2	20% injury reduction

Well-loved Louie the Lightning Bug puts smiles on children's faces at Manitoba Hydro sponsored community events around the province. Games and activities featuring Louie help teach children about energy and safety.

Section:	Recent NFAT Hearing: Attachment H (2012/13 CSP)	**Page No.:**	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets & Strategies		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro provided a copy of the 2012/13 Corporate Strategic Plan in the recent NFAT proceeding.

QUESTION:

Please provide a schedule that set out the various measures and corresponding targets from the 2012/13 CSP and which also shows the actual results for the years 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

Assess Manitoba Hydro's performance relative to its 2012/13 Corporate Strategic Plan which serves as one measure of reasonableness of expenditure. Justifying O, M, & A costs is critical to the reasonableness of rates.

RESPONSE:

Please see the attached table.

Manitoba Hydro 2014/15 & 2015/16 General Rate Application
Round 1 IR - Coalition/MH I-10b

Goal	Measure	2012/13 Target	2012/13 Actual	2013/14 Actual
Improve safety in the workplace	Accident severity rate	< 12 days per 200 000 hours worked	9.7	11.1
	Accident frequency rate	< 0.60 accidents per 200 000 hours worked	0.7	0.7
	High risk incidents	0	0	0
Provide exceptional customer value	System average interruption duration	< 113 minutes which represents the best performing utility in the CEA (5 yr average)	175	106
	System average interruption frequency	<1.4 outages which represents the best performing utility in the CEA (5 yr average)	1.89	1.26
	Canadian Electricity Association (CEA) Customer Service Index	Best in Canada	Among Leading Utilites (Ranked 2nd)	Results not available yet from CEA
	Retail electricity rates (overall)	Lowest in North America	Lowest in North America	Among the lowest in Canada
	Retail natural gas distribution rates	Among the lowest in Canada	Among the lowest in Canada	Among the lowest in Canada
Strengthen working relationships with Aboriginal peoples	*Percentage Aboriginal employment*			
	- Corporate overall	16%	17.0%	17.6%
	- Northern	45%	41.8%	44.1%
	- Management	6%	7.1%	7.1%
	- Professional	8%	7.3%	7.2%
Maintain financial strength	Debt/equity ratio	75:25	75:25	76:24
	Interest Coverage Ratio	>1.2	1.15	1.28
	Capital Coverage Ratio	> 1.2 excluding major generation & transmission	1.25	1.35
	Operation Maintenance and Administration (OM&A) Cost per customer - electric	$814	$844	$865
	OM&A Cost per customer – natural gas	$248	$236	$245
Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba.	Percentage of non-entry positions filled by external applicants	Range 8% - 12%	10.1	10.5
	Percentage of designated group members in Manitoba Hydro workforce			
	Women	26%	24.8%	24.5%
	Women in management	20%	22.9%	22.4%
	Women professionals	35%	33.8%	33.8%
	Women in trades	4%	2.8%	2.5%
	Persons with a disability	6%	10.2%	9.9%
	Visible minorities	7%	7.3%	7.8%
	Visible minorities in management	3%	1.9%	2.4%
	Aboriginal	16%	17.0%	17.6%
Protect the environment in everything that we do	Percent of electricity generated in Manitoba that is renewable	>99%	99.7%	99.6%
	Greenhouse gas emissions*	<520 kilotonnes/yr (6% below 1990 levels)	149	163
Promote cost effective energy conservation and innovation	Demand Side Management (DSM) - electric energy saved	2 069 gigawatt-(GWh) hours per year by March 2013; 3 283 GWh per year by 2025/26	2,269 GW.h	2,486 GW.h
	DSM – electric capacity saved (at winter peak)	612 megawatts (MW) by March 2013; 906 MW by 2025/26	637 MW	688 MW
	DSM - natural gas energy saved	82 million cubic metres per year by March 2013; 153 million cubic metres per year by 2025/26	84 million cubic metres	93 million cubic metres
Be recognized as an outstanding corporate citizen and a driver of economic development in Manitoba	CEA Corporate Citizenship Index	≥ 8.5	6.6	Results not available yet from CEA
	Manitoba Hydro Corporate Citizenship Index	≥ 8.2	7.6	7.5
	Public Contacts – natural gas & electric	20% injury reduction	20 injuries	15 injuries

Notes:
* Corporate emissions tracked by calendar year

Section:	Recent NFAT Hearing: Attachment H (2012/13 CSP)	Page No.:	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Targets & Strategies		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro provided a copy of the 2012/13 Corporate Strategic Plan in the recent NFAT proceeding.

QUESTION:

The 2012/13 Corporate Strategic Plan (page 8) included the following strategy – "Implement and track sustainable initiatives to ensure that OM&A costs are fully justified". Please describe this strategy more fully and provide results to-date.

RATIONALE FOR QUESTION:

Assess Manitoba Hydro's performance relative to its 2012/13 Corporate Strategic Plan which serves as one measure of reasonableness of expenditure. Justifying O, M, & A costs is critical to the reasonableness of rates.

RESPONSE:

Section 5.14 of Tab 5 of the Application is a description of a number of the key initiatives being undertaken by Manitoba Hydro to manage its overall operating & capital expenditures.

Appendix 5.5 of the GRA provides a detailed analysis of Manitoba Hydro's OM&A costs on both an actual and forecast basis for the 5-year period between 2012/13 to 2016/17, and demonstrates the results of Manitoba Hydro's efforts to effectively control costs.

Section:	2012/13 & 2013/14 GRA: Appendix 3.1	**Page No.:**	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Strategies		

PREAMBLE TO IR (IF ANY):

QUESTION:

Has Manitoba Hydro implemented a corporate-wide process for prioritizing capital expenditures?

RATIONALE FOR QUESTION:

The 2011 CSP included as one of its strategies for maintaining financial strength – "Implement a corporate-wide process for prioritizing capital requirements". The reasonableness of prioritization of expenses is important to demonstrate rates are reasonable.

RESPONSE:

Manitoba Hydro has in place an overall framework for the evaluation and prioritization of its capital expenditures which supports the Corporations' objectives relating to customer value, safety, protecting the environment, energy conservation, aboriginal relationships and financial strength.

In consideration of the Corporation's capital investment requirements, funds are allocated in a balanced manner to maintain corporate financial strength, to withstand the risks inherent in Manitoba Hydro's operations and to provide customers with long term rate stability. Investments in major new generation and transmission facilities are supported by the Power Resource Plan which outlines the key assumptions for the Corporation's recommended development plan. Targets for sustaining capital are allocated to the major asset categories (i.e. generation, transmission, distribution and corporate infrastructure) with careful consideration for risk as well as current and future resource demands. On an ongoing basis, approved capital targets are reviewed at the Vice-President level to assess whether a reallocation of funds is required in order to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions as well as operational risk factors. This iterative approach ensures a comprehensive decision making process that aligns business unit priorities with overarching corporate objectives.

The portfolio of projects within an asset category is managed by the responsible Vice-President. Projects are evaluated against a common set of risk criteria with consideration for asset condition and maximizing economic value. Risk factors include public and employee safety, impacts of reliability and capacity on system operations, customer requirements including load growth and environmental impacts. In addition, specific risk criterion may be applied to an asset category, for example the prioritization of transmission projects must consider compliance with the North American Electric Reliability Corporation (NERC) standards. The evaluation of risk considers both the consequence and the probability of occurrence, recognizing that a project may be impacted by multiple risk factors.

The prioritization process utilizes the Capital Project Justification (CPJ) which contains information relative to each project such as system load growth statistics, business case analysis, risk assessment and other pertinent details. In addition, many CPJ's are supported by detailed engineering studies. The requirement and justification for the project is reviewed at multiple levels prior to being forwarded to either the responsible Vice-President or the Executive Committee for approval.

Advancement and deferral of capital projects occurs throughout the year to address changing priorities while managing within approved funding levels. Review and monitoring of project performance is an integral step in order to manage project scope, timing and budget and allows the Corporation to address shifting priorities to effectively manage risk while balancing resource and customer demands. For example, in the event of equipment failure or emergency response, projects posing a lower risk to the Corporation would be deferred. Capital performance monitoring and control occurs at all levels, from individual project management to review and analysis by senior management of the overall capital portfolio.

While the overall framework for capital prioritization is consistently applied across the Corporation, the risk management tools and prioritization processes are customized to address the specific characteristics and risks associated with the varied asset categories within each area.

Section:	2012/13 & 2013/14 GRA: Appendix 3.1	Page No.:	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Strategies		

PREAMBLE TO IR (IF ANY):

QUESTION:

If so, for which IFF/budget year was it first applied?

RATIONALE FOR QUESTION:

The 2011 CSP included as one of its strategies for maintaining financial strength – "Implement a corporate-wide process for prioritizing capital requirements". The reasonableness of prioritization of expenses is important to demonstrate rates are reasonable.

RESPONSE:

Please see the response to COALITION/MH-I-11a for a discussion on the overall framework for the evaluation and prioritization of the Corporation's capital expenditures.

Section:	2012/13 & 2013/14 GRA: Appendix 3.1	Page No.:	
Topic:	Application Overview		
Subtopic:	Corporate Strategic Plan		
Issue:	CSP Strategies		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an overview of how the process works including: i) what factors it takes into account in the prioritization process, ii) how it creates a common basis for comparing the factors for purposes of making trade-offs and ii) how budget limitations/rate impacts are factored into the process.

RATIONALE FOR QUESTION:

The 2011 CSP included as one of its strategies for maintaining financial strength – "Implement a corporate-wide process for prioritizing capital requirements". The reasonableness of prioritization of expenses is important to demonstrate rates are reasonable.

RESPONSE:

Please see the response to COALITION/MH-I-11a.

Section:	Tab 3	**Page No.:**	3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Economic Outlook		
Issue:	Economic Outlook Update		

PREAMBLE TO IR (IF ANY):

The Application notes that certain economic variable were updated from those in the 2014 Economic Outlook to reflect the latest consensus of the source forecasts as of September 2014 (per Appendix 3.1, Attachment B).

QUESTION:

Please provide the most recent forecast from each of the sources used by Manitoba Hydro.

RATIONALE FOR QUESTION:

Manitoba Hydro's Economic Outlook was last updated in the fall of 2014. Given material change in circumstances, an update is necessary.

RESPONSE:

Please see the response to PUB/MH-I-75c.

Section:	Tab 3	**Page No.:**	3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Economic Outlook		
Issue:	Economic Outlook Update		

PREAMBLE TO IR (IF ANY):

The Application notes that certain economic variable were updated from those in the 2014 Economic Outlook to reflect the latest consensus of the source forecasts as of September 2014 (per Appendix 3.1, Attachment B).

QUESTION:

Based on the most recent source forecasts please provide an update to Appendix B.

RATIONALE FOR QUESTION:

Manitoba Hydro's Economic Outlook was last updated in the fall of 2014. Given material change in circumstances, an update is necessary.

RESPONSE:

It is assumed that the reference to "Attachment B" in the Preamble is in reference to Appendix B of the Economic Outlook. The spring 2014 Economic Outlook is filed as Appendix 3.1 of the filing. Appendix B of the Economic Outlook is presented on a calendar year basis and is not consistent with the assumptions used in the filing which are on a fiscal year basis. Rather, Appendix A of the Economic Outlook provides a summary of forecasts on a fiscal year basis and is included as an attachment to this response with updates to interest rates and CAD/USD exchange rate based on updates to end of January 2015 source forecasts.

Economic Outlook Appendix A - January 2015 Update

MANITOBA / CANADA ECONOMIC STATISTICS - FISCAL YEAR BASIS

Year	Man. Real GDP % chge	Man. CPI % chge	Man. Popu-lation '000s	Man. Residential Customers '000s	Cdn. Real GDP % chge	Cdn. CPI % chge	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 10 Yr+ Rate %	C$/ US$
1989/90	2.7	4.7	1,104	385	2.0	5.2	12.37	9.77	1.18
1990/91	1.2	5.0	1,106	387	-1.1	5.0	12.07	10.59	1.16
1991/92	-2.4	3.8	1,110	389	-1.1	4.4	8.03	9.29	1.15
1992/93	0.7	1.9	1,114	391	1.1	1.6	6.25	8.18	1.23
1993/94	1.2	2.4	1,119	394	3.1	1.5	4.46	7.39	1.31
1994/95	2.8	1.6	1,125	396	4.8	0.4	6.46	8.95	1.38
1995/96	0.9	2.5	1,130	398	1.7	2.1	6.17	7.93	1.36
1996/97	3.2	2.5	1,135	400	2.5	1.7	3.67	7.28	1.36
1997/98	4.2	1.5	1,136	404	4.6	1.4	3.63	6.06	1.40
1998/99	3.6	1.5	1,139	405	3.9	0.9	4.81	5.35	1.50
1999/00	2.1	2.2	1,144	408	5.3	2.2	4.82	5.69	1.47
2000/01	3.4	2.5	1,148	411	4.5	2.7	5.42	5.66	1.50
2001/02	1.2	2.1	1,153	413	1.5	2.2	3.09	5.91	1.57
2002/03	1.5	2.3	1,158	415	2.9	3.0	2.79	5.41	1.55
2003/04	1.5	0.9	1,166	419	1.7	1.9	2.67	4.97	1.35
2004/05	2.4	2.7	1,174	422	3.5	2.2	2.31	4.81	1.28
2005/06	3.0	2.4	1,180	426	3.3	2.3	3.02	4.17	1.19
2006/07	3.5	2.0	1,185	430	2.0	1.9	4.16	4.23	1.14
2007/08	3.1	1.9	1,191	434	2.1	2.1	3.83	4.24	1.03
2008/09	2.8	2.2	1,200	440	0.2	2.2	1.84	3.66	1.13
2009/10	0.5	0.6	1,212	444	-1.6	0.4	0.22	3.89	1.09
2010/11	2.4	1.0	1,224	448	3.5	2.0	0.78	3.48	1.02
2011/12	1.9	2.8	1,238	453	2.3	2.8	0.91	2.83	0.99
2012/13	2.5	1.6	1,254	459	1.6	1.2	0.97	2.18	1.00
2013/14	2.2	2.4	1,269	465	2.2	1.1	0.94	2.70	1.05
Forecast									
2014/15	2.2	1.8	1,283	471	2.3	1.6	0.85	2.30	1.13
2015/16	2.5	1.9	1,300	477	2.5	1.9	0.50	2.15	1.29
2016/17	2.7	2.0	1,317	483	2.6	2.0	0.95	2.80	1.25
2017/18	2.6	2.0	1,335	490	2.5	2.1	2.30	3.90	1.13
2018/19	2.1	2.0	1,352	496	2.4	2.0	2.95	3.95	1.11
2019/20	1.8	2.0	1,368	502	2.3	2.0	3.50	3.95	1.10
2020/21	1.6	2.1	1,385	508	1.9	2.0	3.50	4.00	1.09
2021/22	1.6	2.1	1,400	513	1.9	2.0	3.50	4.00	1.09
2022/23	1.6	2.1	1,414	519	1.9	2.0	3.50	4.00	1.09
2023/24	1.6	2.1	1,428	524	1.9	2.0	3.50	4.00	1.10
2024/25	1.6	2.1	1,441	529	1.9	2.0	3.50	4.00	1.10
2025/26	1.6	2.1	1,454	533	1.9	2.0	3.50	4.00	1.10
2026/27	1.6	2.1	1,466	538	1.9	2.0	3.50	4.00	1.10
2027/28	1.6	2.1	1,477	542	1.9	2.0	3.50	4.00	1.10
2028/29	1.6	2.1	1,488	546	1.9	2.0	3.50	4.00	1.10
2029/30	1.6	2.1	1,499	550	1.9	2.0	3.50	4.00	1.10
2030/31	1.6	2.1	1,510	554	1.9	2.0	3.50	4.00	1.10
2031/32	1.6	2.1	1,521	558	1.9	2.0	3.50	4.00	1.10
2032/33	1.6	2.1	1,531	562	1.9	2.0	3.50	4.00	1.10
2033/34	1.6	2.1	1,542	566	1.9	2.0	3.50	4.00	1.10
2034/35	1.6	2.1	1,553	569	1.9	2.0	3.50	4.00	1.10

Section:	Tab 3	**Page No.:**	3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Economic Outlook		
Issue:	Economic Outlook Update		

PREAMBLE TO IR (IF ANY):

The Application notes that certain economic variable were updated from those in the 2014 Economic Outlook to reflect the latest consensus of the source forecasts as of September 2014 (per Appendix 3.1, Attachment B).

QUESTION:

Based on the most recent source forecasts please provide an update to Tab 3, Figure 3.1.

RATIONALE FOR QUESTION:

Manitoba Hydro's Economic Outlook was last updated in the fall of 2014. Given material change in circumstances, an update is necessary.

RESPONSE:

The table below provides an update to Tab 3, Figure 3.1 based on an update of end of January 2015 source forecasts.

	Short-term Interest Rate*	**Long-term Interest Rate***	**USD/CAD**
2014/15	1.85	4.20	1.13
2015/16	1.50	4.00	1.29
2016/17	1.95	4.55	1.25

*Short-term and long-term interest rates include the provincial guarantee fee and applicable credit spreads.

Section:	Tab 3 Tab 5 2012/13 & 2013/14 GRA, Appendix 4.2	**Page No.:**	5 3 31 & 33
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast (MH14)		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

Please confirm that the revenue and expense categories used in Tab 3 and the associated IFF are the same as those used in Tab 5 (page 3). If not, please explain any differences and provide a reconciliation for each of the years 2014/15 – 2016/17.

RATIONALE FOR QUESTION:

To compare MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and for the information request responses subsequently filed during the proceeding, with the actual results for those years. The question goes to the credibility of the rate increase.

RESPONSE:

Confirmed. The 'General Consumers at projected rates' line in Figure 3.2 on page 5 of Tab 3 equals the total of the following line items from Schedules 5.1.0 on page 3 of Tab 5 for 2014/15 to 2016/17:

- General Consumers revenue
- Bipole III Reserve
- Proposed Rate Increases revenue

Section:	Tab 3 Tab 5 2012/13 & 2013/14 GRA, Appendix 4.2	Page No.:	5 3 31 & 33
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast (MH14)		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

For each of the years 2012/13 and 2013/14 please provide a schedule that contrasts the individual Operating Statement values as forecast in MH11-2 with the actual values and provide explanations for any material variances. For reference purposes please also include in the schedule the actual values for 2011/12.

RATIONALE FOR QUESTION:

To compare MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and for the information request responses subsequently filed during the proceeding, with the actual results for those years. The question goes to the credibility of the rate increase.

RESPONSE:

The following table compares forecast MH11-2 with actual results for 2012/13 and 2013/14. Actual results for 2011/12 are provided for reference purposes only. MH11-2 assumes that Manitoba Hydro transitioned to IFRS in 2013/14 and as such some of the variances are attributable to this difference in accounting standards. On an actual basis, Manitoba Hydro will not be transitioning to IFRS until 2015/16.

MANITOBA HYDRO
STATEMENT OF INCOME
(in thousands)

	2011/12 Actual	2012/13 Actual	2012/13 MH11-2	2013/14 Actual	2013/14 MH11-2
Revenue					
General Consumers	1 192 797	1 341 011	1 335 571	1 424 127	1 399 088
Bipole III Reserve	-	-	-	(18 826)	-
Extraprovincial	363 044	352 633	341 167	439 182	362 920
Other	13 848	29 854	15 706	21 758	16 078
Total Revenue	$ 1 569 689	$ 1 723 497	$ 1 692 445	$ 1 866 241	$ 1 778 086
Expenses					
Operating, Maintenance and Administrative	412 035	462 952	446 966	480 717	531 825
Finance Expense	385 044	452 367	439 641	435 402	451 643
Depreciation and Amortization	353 376	391 923	400 846	410 834	354 307
Water Rentals and Assessments	119 300	117 864	105 900	125 517	112 470
Fuel and Power Purchased	145 632	133 292	182 478	177 113	158 040
Capital and Other Taxes	82 888	86 399	87 197	96 750	92 056
Corporate Allocation	8 880	9 074	8 835	9 074	8 336
Other Expenses	1 180	4 750	-	6 294	
Total Expenses	1 508 334	1 658 621	1 671 863	1 741 700	1 708 677
Non-controlling Interest	-	13 160	(979)	22 005	(949)
Net Income	$ 61 354	$ 78 037	$ 19 603	$ 146 545	$ 68 460

2012/13 Actual vs. 2012/13 MH11-2

Net income from electricity operations was higher than forecast primarily due to increased revenues from domestic electricity sales mainly attributable to colder weather, higher extraprovincial electricity sales and higher other revenue resulting from gains on the sale of land and apprenticeship tax credits. In addition, lower expenses contributed to the higher than forecast net income.

The reduction in expenses was primarily the result of lower fuel and power purchased attributable to lower wind generation and lower imports resulting from favourable water conditions and lower depreciation and amortization due to lower spending on Affordable Energy programs and the timing of projects going into service including the Wuskwatim Generating Station. These reductions were partially offset by higher operating, maintenance and administrative expense related to storm restoration activities and higher pension and benefit costs due to the change in discount rate, higher finance expense due to greater volumes of long-term debt to finance capital expenditures and higher water rentals and assessments reflecting greater hydraulic generation due to higher water flows.

Non-controlling interest was higher than forecast due to a difference in forecasting methodology. MH11-2 assumed Taskinigahp Power Corporation (TPC) was a preferred equity holder in Wuskwatim Power Limited Partnership (WPLP) thereby not sharing in WPLP's reported net loss for 2012-13. On an actual basis, TPC's share of the net loss was $13 million.

2013/14 Actual vs. 2013/14 MH11-2

Net income from electricity operations was higher than forecast primarily due to increased extraprovincial electricity sales due to higher sales volumes, export prices and system merchant sales, and increased domestic electricity sales due to colder weather which was partially offset by revenues set aside for the Bipole III reserve.

The increase in revenue was partially offset by higher depreciation and amortization mainly attributable to IFRS impacts reflected in the forecast (MH11-2 had assumed a transition to IFRS in 2013/14) including removal of regulatory deferrals, removal of negative salvage and change to equal life group depreciation. In addition, the increase in revenue was partially offset by higher water rentals and assessments attributable to greater hydraulic generation due to higher water flows and higher fuel and power purchased primarily due to higher purchased volumes due to colder weather. These increases were partially offset by a reduction in operating, maintenance and administrative expense primarily attributable to IFRS impacts reflected in the forecast associated with reduced capitalization of overhead costs and a reduction in finance expense primarily due to gains on the sale of sinking fund investments.

Non-controlling interest was higher than forecast due to a difference in forecasting methodology. MH11-2 assumed TPC was a preferred equity holder in WPLP thereby not sharing in WPLP's reported net loss for 2013-14. On an actual basis, TPC's share of the net loss was $22 million.

Section:	Tab 3 Tab 5 2012/13 & 2013/14 GRA, Appendix 4.2	Page No.:	5 3 31 & 33
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast (MH14)		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

For each of the years 2012/13 and 2013/14 please provide a schedule that compares the individual Balance Sheet values as forecast in MH11-2 with the actual values and provide explanations for any material variances. For reference purposes, please also include the actual values for 2011/12.

RATIONALE FOR QUESTION:

To compare MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and for the information request responses subsequently filed during the proceeding, with the actual results for those years. The question goes to the credibility of the rate increase.

RESPONSE:

The following table compares forecast MH11-2 with actual results for 2012/13 and 2013/14. Actual results for 2011/12 are provided for reference purposes only. MH11-2 assumes that Manitoba Hydro transitioned to IFRS in 2013/14 and as such some of the variances are attributable to this difference in accounting standards. On an actual basis, Manitoba Hydro will not be transitioning to IFRS until 2015/16.

MANITOBA HYDRO
ELECTRIC OPERATIONS BALANCE SHEET
For the year ended March 31
(millions of dollars)

	2011/12 Actual	2012/13 Actual	2012/13 MH11-2	2013/14 Actual	2013/14 MH11-2
Assets					
Plant in service	12 994	15 132	15 212	15 506	15 723
Accumulated depreciation	4 760	5 020	5 266	5 266	5 581
Net plant in service	8 234	10 112	9 946	10 240	10 142
Construction in progress	3 148	1 965	2 196	2 939	3 149
Current and other assets	1 713	1 743	2 242	1 663	1 447
Goodwill	108	108	42	108	42
	$ 13 203	$ 13 928	$ 14 427	$ 14 950	$ 14 780
Liabilities and Retained Earnings					
Long-term debt	8 866	9 034	9 469	10 190	10 909
Current and other liabilities	1 209	1 693	1 917	1 598	1 407
Contributions in aid of construction	285	307	328	339	341
Non-controlling interest	100	95	-	73	-
Retained earnings	2 416	2 500	2 411	2 654	2 203
Accumulated other comprehensive income (loss)	327	299	302	96	(79)
	$ 13 203	$ 13 928	$ 14 427	$ 14 950	$ 14 780

2012/13 Actual vs. 2012/13 MH11-2

Construction in progress is lower than forecast primarily due to delays in construction of Keeyask, Conawapa and Pointe du Bois Spillway. Current and other assets are lower than forecast primarily due to a difference in forecasting methodology. Included in the forecast is Centra’s acquisition purchase price as well as Centra’s intercompany loan receivable, both of which are eliminated on consolidation on an actual basis. Long-term debt is lower than forecast due to lower debt requirements resulting from reduced capital spending. The reduction in current and other liabilities is primarily due to lower than forecast current portion debt balances. Non-controlling interest is higher than forecast due to a difference in forecasting methodology. MH11-2 assumed there was a preferred equity ownership arrangement with Taskinigahp Power Corporation (TPC).

2013/14 Actual vs. 2013/14 MH11-2

Construction in progress is lower than forecast primarily due to delays in construction of Keeyask, Conawapa and Pointe du Bois Spillway. Current and other assets are higher than forecast primarily due to IFRS impacts reflected in the forecast (MH11-2 had assumed a transition to IFRS in 2013/14) including the elimination of regulatory deferrals and pension adjustment to accumulated other comprehensive income. These increases were largely offset by the differences in forecasting methodology related to Centra's acquisition and intercompany loans. The decrease in long-term debt is attributable to lower debt requirements due to reduced capital spending and increased cash receipts from domestic and extraprovincial customers primarily due to colder weather. The increase in current and other liabilities is primarily due to higher than forecast current portion debt balances. Non-controlling interest is higher than forecast due to a difference in forecasting methodology. MH11-2 assumed there was a preferred equity ownership arrangement with TPC. Accumulated other comprehensive income is higher than forecast largely due to the IFRS-related pension adjustment included in the forecast related to the reclassification of unrealized experience gains and losses.

Section:	Tab 3: Figure 3.2 Tab 5, Figure 5.1.0	Page No.:	5 3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

Please provide a schedule similar to Figure 3.2 but which contrasts MH11-2 with MH14 for: i) each of the years 2014/15-2016/17 and ii) the period 2014/15-2023/24.

RATIONALE FOR QUESTION:

Understand what has changed from MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and the basis for the information request responses subsequently filed during the proceeding, and from MH12, which was filed during the last GRA, as compared to the current MH14 forecast. The issue goes to credibility of Hydro's current forecasts which is central to rate setting.

RESPONSE:

Please see the following table comparing MH14 vs MH11-2.

Comparison of Electrical Operations MH14 to MH11-2
Increase/(Decrease)
(millions of $)

	2015-2017			2015-2024		
	MH14	MH11-2	Variance	MH14	MH11-2	Variance
General Consumers at projected rates	4 430	4 578	(148)	17 755	18 145	(390)
Extraprovincial	1 293	1 365	(72)	6 449	6 672	(223)
Other	43	50	(7)	149	180	(30)
Total Revenues	5 766	5 994	(228)	24 353	24 996	(643)
Operating and Administrative	1 579	1 643	(64)	5 751	5 902	(152)
Finance Expense	1 553	1 611	(58)	8 975	8 244	731
Depreciation and Amortization	1 228	1 119	108	5 486	4 781	705
Water Rentals and Assessments	359	339	20	1 213	1 187	27
Fuel and Power Purchased	456	583	(128)	2 091	2 371	(280)
Capital and Other Taxes	327	322	5	1 355	1 266	89
Corporate Allocation	25	25	0	83	83	(0)
Other Expenses	7	-	7	25	-	25
	5 534	5 643	(109)	24 980	23 834	1 146
Non-controlling Interest	45	(5)	50	68	(48)	116
Net Income	277	345	(68)	(559)	1 114	(1 673)

Section:	Tab 3: Figure 3.2 Tab 5, Figure 5.1.0	**Page No.:**	5 3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

Please provide a commentary similar to that in PUB/MH I-22 (from the last GRA) that explains, by revenue and expense category, the variances between the two financial projections (i.e. MH11-2 and MH14) for i) each of the years 2014/15 to 2016/17 and ii) the period 2014/15 to 2023/24.

RATIONALE FOR QUESTION:

Understand what has changed from MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and the basis for the information request responses subsequently filed during the proceeding, and from MH12, which was filed during the last GRA, as compared to the current MH14 forecast. The issue goes to credibility of Hydro's current forecasts which is central to rate setting.

RESPONSE:

Please see the following table.

ELECTRIC OPERATIONS
COMPARISON OF MH14 To MH11-2
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2015	2016	2017	CUMULATIVE 2015-2024	VARIANCE EXPLANATION
REVENUES					
General Consumers Revenue including Projected Rate Increases	(56)	(42)	(50)	(390)	Lower GCR revenue is primarily due to more aggressive DSM programs resulting in greater energy and capacity savings; Order 49/14 approved 2.75% interim rate increase compared to 3.5% projected in MH11-2; Orders 43/13 and 49/14, directed 1.5% and 0.75% of the respective rate increases to be set aside in a deferral account to be used to offset the anticipated rate impact when Bipole III is placed in-service.
Extraprovincial	15	(35)	(53)	(223)	Lower extraprovincial revenue due to a lower export price forecast partially offset by increased volumes from lower MB load forecast as a result of more aggressive DSM program as noted above; weakening of the Canadian dollar and increased US tieline export capability.
Other	(1)	(3)	(3)	(30)	
Total Revenue	**(42)**	**(79)**	**(106)**	**(643)**	
EXPENSES					
Operating and Administrative	(56)	(6)	(2)	(152)	Lower OM&A due to IFRS 2 year deferral from 2013/14 to 2015/16; continuation of regulatory deferral accounts (expensed DSM, site remediation, regulatory costs and deferred taxes under IFRS in MH11-2); implementation of more aggressive cost constraints limiting increases to below inflationary levels of 1%; and 9 month deferral of Bipole III; partially offset by increases in ineligible overhead and higher pension costs due to discount rate reductions.
Finance Expense	(9)	(26)	(23)	731	Lower finance expense 2015/16 to 2018/19 due to lower interest rates and deferral of Bipole III; higher finance expense 2019/20 to 2023/24 due to higher capital expenditures for Bipole III, Keeyask, DSM and aging infrastructure, suspension of Conawapa and associated interest capitalized, and the weakening Canadian dollar; partially offset by lower interest rates.
Depreciation and Amortization	47	26	36	706	Higher depreciation and amortization due to higher capital expenditures noted in finance expense; continuation of regulatory deferral accounts and corresponding amortization noted in OM&A above; and the amortization of Conawapa sunk costs; partially offset by lower depreciation rates resulting from the 2014 Depreciation Study.
Water Rentals and Assessments	12	10	(1)	27	Higher water rentals 2014/15 & 2015/16 due to change in forecast assumption from average of all flows in MH11-2 to expected and median water flow conditions in MH14.
Fuel and Power Purchased	(52)	(62)	(13)	(280)	Lower import and thermal requirements in 2014/15 and 2015/16 due to change in forecast assumption noted for water rentals above; lower forecast export prices over forecast period to 2023/24.
Capital and Other Taxes	0	(0)	5	89	Higher capital taxes due to higher capital expenditures for Bipole III, Keeyask, DSM and aging infrastructure partially offset by suspension of Conawapa.
Corporate Allocation	0	0	0	(0)	
Other Expenses	2	2	2	25	
Total Expenses	**(56)**	**(57)**	**4**	**1 146**	
Non-controlling Interest	27	14	10	116	MH11-2 assumed NCN is a preferred unit holder in WPLP for forecast purposes and non-controlling interest reflected the preferred distributions. MH14 assumed NCN is a common unit holder and NCI reflect NCN's 33% share of WPLP net income or losses.
Change in Net Income	**41**	**(9)**	**(100)**	**(1 673)**	

Section:	Tab 3: Figure 3.2 Tab 5, Figure 5.1.0	Page No.:	5 3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

It is noted that DSM affects both revenues and expenses over these periods. What is the overall impact of the increased DSM spending and associated energy/capacity savings in MH14 on net income for the periods 2015-2017 and 2015-2024 when MH14 is compared to MH11-2, after taking into account all of these impacts?

RATIONALE FOR QUESTION:

Understand what has changed from MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and the basis for the information request responses subsequently filed during the proceeding, and from MH12, which was filed during the last GRA, as compared to the current MH14 forecast. The issue goes to credibility of Hydro's current forecasts which is central to rate setting.

RESPONSE:

Please see the response to PUB/MH-I-59a.

The DSM assumed in MH14 targets consumption savings which are significantly more than what was assumed in MH11-2previous forecasts. The response to PUB/MH I-59a provides a scenario that reflects DSM savings reduced by 50% per year over the forecast period from

2015/16 to 2033/34 effectively approximates the overall impact of the increased DSM spending on both the revenues and expenses.

Section:	Tab 3: Figure 3.2 Tab 5, Figure 5.1.0	**Page No.:**	5 3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

Please provide a schedule similar to Figure 3.2 but which contrasts MH12 with MH14 for: i) each of the years 2015-2017 and ii) the period 2015-2024.

RATIONALE FOR QUESTION:

Understand what has changed from MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and the basis for the information request responses subsequently filed during the proceeding, and from MH12, which was filed during the last GRA, as compared to the current MH14 forecast. The issue goes to credibility of Hydro's current forecasts which is central to rate setting.

RESPONSE:

Please see the following table comparing MH14 vs MH12.

Comparison of Electrical Operations MH14 to MH12
Increase/(Decrease)
(millions of $)

	2015-2017			2015-2024		
	MH14	MH12	Variance	MH14	MH12	Variance
General Consumers at projected rates	4 430	4 664	(234)	17 755	18 860	(1 105)
Extraprovincial	1 293	1 130	163	6 449	5 756	693
Other	43	45	(2)	149	162	(13)
Total Revenues	5 766	5 839	(73)	24 353	24 778	(425)
Operating and Administrative	1 579	1 667	(87)	5 751	6 115	(364)
Finance Expense	1 553	1 602	(49)	8 975	8 077	898
Depreciation and Amortization	1 228	1 174	54	5 486	5 089	397
Water Rentals and Assessments	359	335	24	1 213	1 174	39
Fuel and Power Purchased	456	576	(121)	2 091	2 345	(255)
Capital and Other Taxes	327	330	(3)	1 355	1 389	(34)
Corporate Allocation	25	25	0	83	83	(0)
Other Expenses	7	-	7	25	-	25
	5 534	5 709	(175)	24 980	24 273	706
Non-controlling Interest	45	50	(5)	68	55	13
Net Income	277	180	97	(559)	559	(1 118)

Section:	Tab 3: Figure 3.2 Tab 5, Figure 5.1.0	Page No.:	5 3
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

It is noted that the Application in the last GRA was filed based on IFF11-2 and that IFF12 was subsequently filed during the proceeding.

QUESTION:

Please provide a commentary similar to that in PUB/MH I-22 (from the last GRA) that explains, by revenue and expense category, the variances between the two financial projections (i.e., MH12 and MH14) for: i) each of the years 2014/15-2016/17 and ii) the period 2014/15-2023/24..

RATIONALE FOR QUESTION:

Understand what has changed from MH11-2, which was the basis for the initial 2012/13 & 2013/14 GRA and the basis for the information request responses subsequently filed during the proceeding, and from MH12, which was filed during the last GRA, as compared to the current MH14 forecast. The issue goes to credibility of Hydro's current forecasts which is central to rate setting.

RESPONSE:

Please see the explanations for changes in forecast from MH12 to MH14 by line item in the table below.

ELECTRIC OPERATIONS
COMPARISON OF MH14 To MH12
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2015	2016	2017	CUMULATIVE 2015-2024	VARIANCE EXPLANATION
REVENUES					
General Consumers Revenue at Projected Rate Increases	(71)	(75)	(88)	(1,105)	Lower GCR revenue is primarily due to more aggressive DSM programs resulting in greater energy and capacity savings; Order 49/14 approved 2.75% interim rate increase compared to 3.95% projected in MH12; Orders 43/13 and 49/14, directed 1.5% and 0.75% of the respective rate increases to be set aside in a deferral account to be used to offset the anticipated rate impact when Bipole III is placed in-service.
Extraprovincial	65	54	43	693	Higher extraprovincial revenue due to lower MB load forecast as a result of more aggressive DSM program as noted above; weakening of the Canadian dollar; increased US tieline export capability; partially offset by lower export price forecast.
Other	0	(1)	(1)	(13)	
Total Revenue	**(5)**	**(22)**	**(46)**	**(425)**	
EXPENSES					
Operating and Administrative	(58)	(14)	(15)	(364)	Lower OM&A due to IFRS 1 year deferral from 2014/15 to 2015/16; continuation of regulatory deferral accounts (expensed DSM, site remediation, regulatory costs and deferred taxes under IFRS in MH12); implementation of more aggressive cost constraints limiting increases to below inflationary levels of 1%; and 9 month deferral of Bipole III; partially offset by increases in ineligible overhead and higher pension costs due to discount rate reductions.
Finance Expense	3	(14)	(38)	898	Lower finance expense 2015/16 to 2018/19 due to lower interest rates and deferral of Bipole III; higher finance expense 2019/20 to 2023/24 due to higher capital expenditures for Bipole III, Keeyask, DSM and aging infrastructure, and the weakening Canadian dollar; partially offset by lower interest rates.
Depreciation and Amortization	32	10	12	397	Higher depreciation and amortization due to higher capital expenditures noted in finance expense; continuation of regulatory deferral accounts and corresponding amortization noted in OM&A above; partially offset by lower depreciation rates resulting from 2014 Depreciation Study.
Water Rentals and Assessments	13	11	0	39	Higher water rentals 2014/15 & 2015/16 due to change in forecast assumption from average of all flows in MH12 to expected and median water flow conditions in MH14.
Fuel and Power Purchased	(45)	(61)	(15)	(255)	Lower import and thermal requirements in 2014/15 and 2015/16 due to change in assumption noted for water rentals above; lower forecast export prices over forecast period to 2023/24.
Capital and Other Taxes	(2)	(3)	1	(34)	Lower capital taxes due to suspension of Conawapa.
Corporate Allocation	0	0	0	(0)	
Other Expenses	2	2	2	25	
Total Expenses	**(54)**	**(68)**	**(53)**	**706**	
Non-controlling Interest	4	(3)	(5)	13	
Change in Net Income	**52**	**42**	**2**	**(1,118)**	

Section:	Tab 3	Page No.:	6
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Reclassification of GNTL costs		

PREAMBLE TO IR (IF ANY):

The Application makes reference (page 6) to a change in the classification of the Great Northern Transmission Line (GNTL) costs.

QUESTION:

In which IFF were the costs of the Great Northern Transmission Line (GNTL) first included?

RATIONALE FOR QUESTION:

Manitoba Hydro has changed the classification of GNTL costs. The request seeks to clarify the appropriateness of incorporating certain costs into rates. The information request seeks different information than posed in PUB/MH 1-21.

RESPONSE:

The costs of the Great Northern Transmission Line (GNTL) were first included in the NFAT financial evaluations which were based on IFF12 updated for expected 2013 electricity export prices and the GNTL costs. IFF13 was the first IFF which included the GNTL costs.

Section:	Tab 3	**Page No.:**	6
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Reclassification of GNTL costs		

PREAMBLE TO IR (IF ANY):

The Application makes reference (page 6) to a change in the classification of the Great Northern Transmission Line (GNTL) costs.

QUESTION:

Please describe what these costs are for and how they are determined.

RATIONALE FOR QUESTION:

Manitoba Hydro has changed the classification of GNTL costs. The request seeks to clarify the appropriateness of incorporating certain costs into rates. The information request seeks different information than posed in PUB/MH 1-21.

RESPONSE:

Costs included in MH14 for the Great Northern Transmission Line (GNTL) include both Manitoba Hydro internal project costs and costs shared with Minnesota Power. Internal Manitoba Hydro costs include salaries, staff time, travel costs, legal fees, consulting services, engineering studies, escalation and interest, and project overhead. Shared costs with Minnesota Power include all items associated with developing and constructing the transmission line and other transmission system upgrades (engineering, permitting, material procurement, scheduling, quality control, safety, construction and development agreements, project management, etc).

The project costs are shared by Manitoba Hydro (54%) and Minnesota Power (46%) in accordance with the Facilities Construction Agreement.

Once the GNTL is in-service, Manitoba Hydro will pay 49% of the projected annual operating costs for the GNTL.

In addition, Minnesota Power will charge Manitoba Hydro a scheduling fee under the 133 MW Power Purchase Agreement.

Please see the response to COALITION/MH-I-15c for a schedule of costs reflected in IFF13 and IFF14.

Section:	Tab 3	**Page No.:**	6
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Reclassification of GNTL costs		

PREAMBLE TO IR (IF ANY):

The Application makes reference (page 6) to a change in the classification of the Great Northern Transmission Line (GNTL) costs.

QUESTION:

Please provide a schedule that sets out, for each IFF (from IFF11-2 through to IFF14) that included costs for the GNTL, the annual costs from the initial year of first inclusion through to 2023/24 and how they were classified.

RATIONALE FOR QUESTION:

Manitoba Hydro has changed the classification of GNTL costs. The request seeks to clarify the appropriateness of incorporating certain costs into rates. The information request seeks different information than posed in PUB/MH 1-21.

RESPONSE:

As noted in COALITION/MH-I-15a, the costs of the Great Northern Transmission Line (GNTL) were first included in the NFAT financial evaluations which were based on IFF12 updated for expected 2013 electricity export prices and the GNTL costs. IFF13 was the first IFF which included the GNTL costs. Please see the attached schedules that set out the costs included in IFF14 and IFF13 relating to the GNTL.

The revised costs reflect the finalization of the Facilities Construction Agreement (FCA) with Minnesota Power and the Midcontinent Independent System Operator (MISO) and the 133 MW Power Purchase Agreement (see the response to COALITION/MH-I-15b). Manitoba Hydro's 54% share of projected pre-certification and construction costs are $542 million in

IFF14, approximately $232 million higher compared to IFF13, due to the completion of a more detailed line routing plan, the redistribution of costs amongst project participants (IFF13 assumed a third project participant), internal and legal costs incurred in the development phase, and a weakened Canadian dollar. The FCA grants transmission service rights to Manitoba Hydro, and as a result, pre-certification and construction costs are assumed to be recognized as an intangible asset. The projected pre-certification and construction costs were previously included in capital expenditures in IFF13 and are reclassified to an intangible asset in IFF14.

The present value of the projected scheduling fee under the 133 MW Power Purchase Agreement is $286 million and is assumed to be recorded as part of the intangible asset in 2020/21, following completion of the construction of the GNTL and commencing with the start of the 133 MW power purchase agreement, with a corresponding liability. In IFF13, the projected scheduling fees were expensed in fuel and power purchases.

The costs charged to the intangible asset are assumed to be amortized over 40 years, consistent with the transmission requirements and rollover rights of power sales agreements in place between Manitoba Hydro and Minnesota Power. IFF14 also recognizes accretion on the liability related to the discounted scheduling fee which is recorded annually in finance expense.

The projected annual operating costs and property taxes for the GNTL are assumed to be recorded as a period transmission charge in fuel and power purchases. This is reclassified from operating and administration expense in IFF13.

IFF14 - Costs Associated with the GNTL
(in Millions)

Fiscal Year Ending	Capital Expenditures	PV of Scheduling Fee (Liability & Intangible Asset)	Accretion on the Liability (Finance Expense)	Amortization of Intangible Asset (Depreciation Expense)	49% Funding Transmission Charges (Fuel & Power Purchase Expense)
2014	7	-	-	-	-
2015	8	-	-	-	-
2016	18	-	-	-	-
2017	59	-	-	-	-
2018	122	-	-	-	-
2019	182	-	-	-	-
2020	127	-	-	-	-
2021	18	286	18	16	16
2022	-	-	17	21	16
2023	-	-	16	21	15
2024	-	-	15	21	15
Total to 2024	$ 542	$ 286	$ 65	$ 78	$ 62

IFF13 - Costs Associated with the GNTL
(in Millions)

Fiscal Year Ending	Capital Expenditures	Depreciation on Capital Expenditures	49% Funding Transmission Charges (Operating & Admin Expense)	Scheduling Fee (Fuel & Power Purchases Expense)
2014	3	-	-	-
2015	3	-	-	-
2016	2	-	-	-
2017	0	-	-	-
2018	73	-	-	-
2019	29	1	-	-
2020	201	5	-	-
2021	-	8	9	26
2022	-	8	9	24
2023	-	8	9	23
2024	-	8	9	21
Total to 2024	$ 310	$ 38	$ 37	$ 94

Section:	Tab 3	**Page No.:**	6
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Reclassification of GNTL costs		

PREAMBLE TO IR (IF ANY):

The Application makes reference (page 6) to a change in the classification of the Great Northern Transmission Line (GNTL) costs.

QUESTION:

What year is the GNTL expected to come in-service? If the IFF14 Operating Statement includes costs for the GNTL prior to the in-service year, please explain why this is appropriate.

RATIONALE FOR QUESTION:

Manitoba Hydro has changed the classification of GNTL costs. The request seeks to clarify the appropriateness of incorporating certain costs into rates. The information request seeks different information than posed in PUB/MH 1-21.

RESPONSE:

The expected in-service date of the GNTL is May of 2020. There are no GNTL costs included in the Electric operating statement prior to the in-service date.

Section:	Tab 3 2012/13 & 2013/14 GRA, MIPUG/MH I-2	Page No.:	11
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Review of Financial Targets		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-2 (from the last GRA) makes reference to a review of Manitoba Hydro's financial targets that was to be completed by November 2012

QUESTION:

Please provide a copy of the review of financial targets referenced in MIPUG/MH I-2 (from the last GRA)

RATIONALE FOR QUESTION:

Manitoba Hydro has recently commenced a review of its financial targets which are an important element of rate setting. The request goes to the reasonableness of the evaluation process and the expenditure on the evaluation process.

RESPONSE:

The approved financial targets for debt/equity (75:25), interest coverage (>1.20) and capital coverage (>1.20) were reaffirmed by the Manitoba Hydro-Electric Board in November 2012 based on the projections included in IFF12, which projected that the targets would not be met until 2031/32, 2025/26, and 2016/17, respectively. Financial targets were retained for purposes of measuring the financial performance until a formal external review was completed.

A formal external review was deferred until the completion of the NFAT and is currently underway.

Section:	Tab 3 2012/13 & 2013/14 GRA, MIPUG/MH I-2	**Page No.:**	11
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Review of Financial Targets		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-2 (from the last GRA) makes reference to a review of Manitoba Hydro's financial targets that was to be completed by November 2012

QUESTION:

Please explain why Manitoba Hydro did not schedule its current review of financial targets earlier so as to comply with the PUB's direction from Order 43/13 and have it available for the current GRA..

RATIONALE FOR QUESTION:

Manitoba Hydro has recently commenced a review of its financial targets which are an important element of rate setting. The request goes to the reasonableness of the evaluation process and the expenditure on the evaluation process.

RESPONSE:

Manitoba Hydro began planning and the process of engaging expert consultants for the Financial Target Review following the conclusion of the Need For and Alternative To (NFAT) review. The staff required to provide analysis for the Financial Target Review were integral to the NFAT review and not available prior to its conclusion.

Additionally, the commencement of the 2014 integrated planning process, which provides inputs to the IFF14, was delayed until the conclusion of the NFAT. Significant resources were assigned to the preparation of IFF14 in order to complete the forecast within the normal timeframe despite the delayed start.

Section:	Tab 3 2012/13 & 2013/14 GRA, MIPUG/MH I-2	Page No.:	11
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Review of Financial Targets		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-2 (from the last GRA) makes reference to a review of Manitoba Hydro's financial targets that was to be completed by November 2012

QUESTION:

How was KPMG selected to carry out the current review of financial targets, operating & financial risks and adequacy of reserves?

RATIONALE FOR QUESTION:

Manitoba Hydro has recently commenced a review of its financial targets which are an important element of rate setting. The request goes to the reasonableness of the evaluation process and the expenditure on the evaluation process.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Tab 3 2012/13 & 2013/14 GRA, MIPUG/MH I-2	**Page No.:**	11
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Review of Financial Targets		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-2 (from the last GRA) makes reference to a review of Manitoba Hydro's financial targets that was to be completed by November 2012

QUESTION:

If the selection was through an RFP process, please provide a copy of the RFP.

RATIONALE FOR QUESTION:

Manitoba Hydro has recently commenced a review of its financial targets which are an important element of rate setting. The request goes to the reasonableness of the evaluation process and the expenditure on the evaluation process.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Tab 11 Tab 10	**Page No.:**	4 5
Topic:	Minimum Filing Requirements		
Subtopic:	Corporate Overview		
Issue:	Corporate Risk		

PREAMBLE TO IR (IF ANY):

At Tab 10 (page 5, lines 11-15), the Application suggests that the information currently filed on risks is sufficient. However, Tab 11 suggests that additional information will be forthcoming.

QUESTION:

If not provided as part of the interrogatory responses, please indicate what Manitoba Hydro plans on providing as a response to Corporate Overview MFR #10 (per Tab 11, page 4).

RATIONALE FOR QUESTION:

Clarification is sought regarding the information Manitoba Hydro plans on providing additional information regarding Corporate risks and risk management. Risk and risk mitigation is an important element of rate setting.

RESPONSE:

Please see Appendix 11.7, Corporate Overview MFR 10 for a redacted version of Manitoba Hydro's Corporate Risk Management Report.

Section:	Tab 3: Figures 3.4, 3.5 and 3.6	Page No.:	13, 15 & 16
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Comparison of Forecasts and Actual Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a set of schedules that set out the values for MH's consolidated financial targets as forecast in IFF11-2 and IFF12 for 2012/13 and 2013/14. In the same schedule please provide the actual values for the two years.

RATIONALE FOR QUESTION:

Compare actual financial target results with forecasts from the previous GRA. Credibility of forecasting is central to rate setting.

RESPONSE:

As indicated in section 3.4.1 of Tab 3, Manitoba Hydro's consolidated financial targets are as follows:

1. Debt/Equity: Maintain a minimum debt/equity ratio of 75:25.
2. Interest Coverage: Maintain a minimum annual gross interest coverage ratio of greater than 1.20.
3. Capital Coverage: Maintain a capital coverage ratio of greater than 1.20 (excepting new major generation and transmission).

These targets are the same in IFF11-2 and IFF12.

Please see the following table for the requested information.

Equity	2012/13	2013/14
Target	25%	25%
IFF11-2	24%	18%
IFF12	25%	22%
Actual Consolidated	25%	24%

Equity	2012/13	2013/14
MH11-2	24%	19%
MH12	25%	22%
Actual Electric Only	25%	23%

Interest Coverage	2012/13	2013/14
Target	1.20	1.20
IFF11-2	1.05	1.12
IFF12	1.10	1.11
Actual Consolidated	1.15	1.28

Interest Coverage	2012/13	2013/14
MH11-2	1.03	1.11
MH12	1.09	1.10
Actual Electric Only	1.13	1.25

Capital Coverage	2012/13	2013/14
Target	1.20	1.20
IFF11-2	1.19	1.18
IFF12	1.16	0.89
Actual Consolidated	1.25	1.35

Capital Coverage	2012/13	2013/14
MH11-2	1.07	1.13
MH12	1.09	0.89
Actual Electric Only	1.26	1.39

Section:	Tab 3: Figures 3.4, 3.5 and 3.6	**Page No.:**	13, 15 & 16
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Financial Targets		
Issue:	Comparison of Forecasts and Actual Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please also provide a set of schedules that set out the values for MH-electric's financial targets as forecast in IFF11-2 and IFF12 for 2012/13 and 2013/14. In the same schedule please provide the actual values for the two years.

RATIONALE FOR QUESTION:

Compare actual financial target results with forecasts from the previous GRA. Credibility of forecasting is central to rate setting.

RESPONSE:

As indicated in section 3.4.1 of Tab 3, Manitoba Hydro only sets consolidated financial targets. Please see COALITION/MH-I-18a for the projected and actual information with respect to Electric operations.

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the materials in Appendix 11.14 to include the years back to 2011/12 and the results from IFF11-2 and IFF12. Please report actual values were appropriate

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

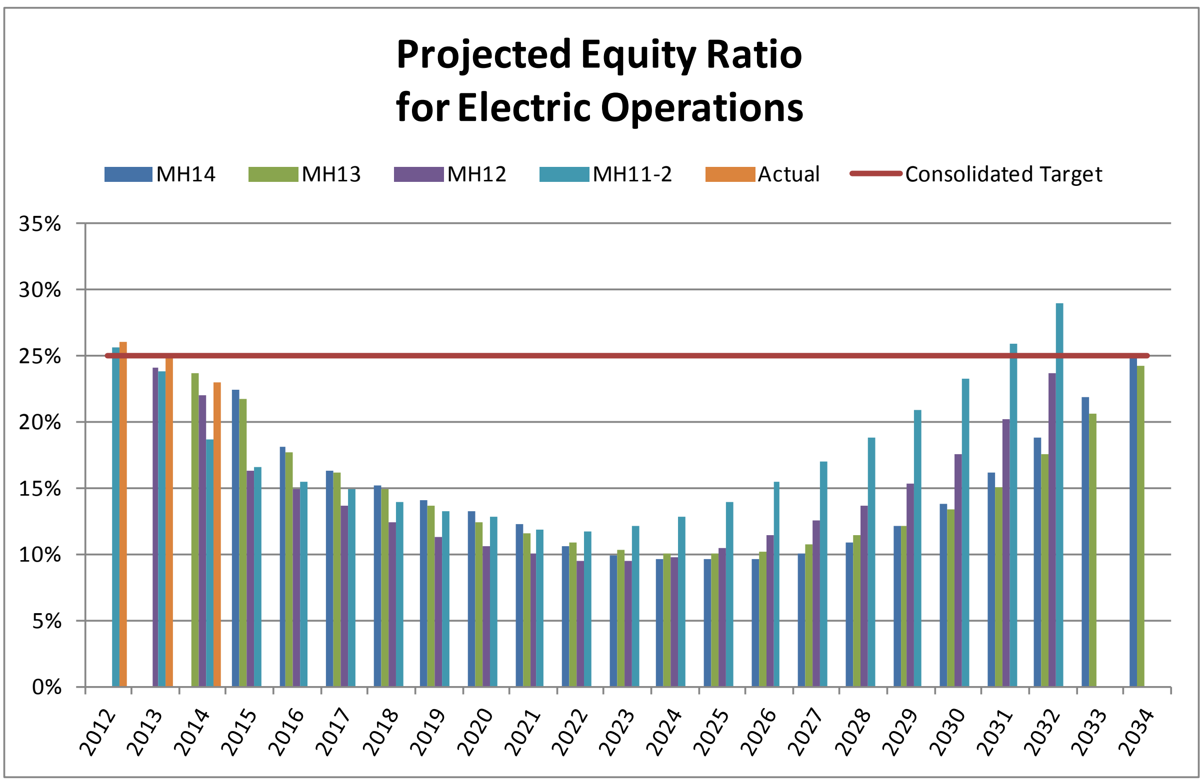
RESPONSE:

Please see the following tables.

Equity Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
MH14				22%	18%	16%	15%	14%	13%	12%	11%	10%
MH13			24%	22%	18%	16%	15%	14%	12%	12%	11%	10%
MH12		24%	22%	16%	15%	14%	12%	11%	11%	10%	9%	9%
MH11-2	26%	24%	19%	17%	15%	15%	14%	13%	13%	12%	12%	12%
Actual	26%	25%	23%									
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%

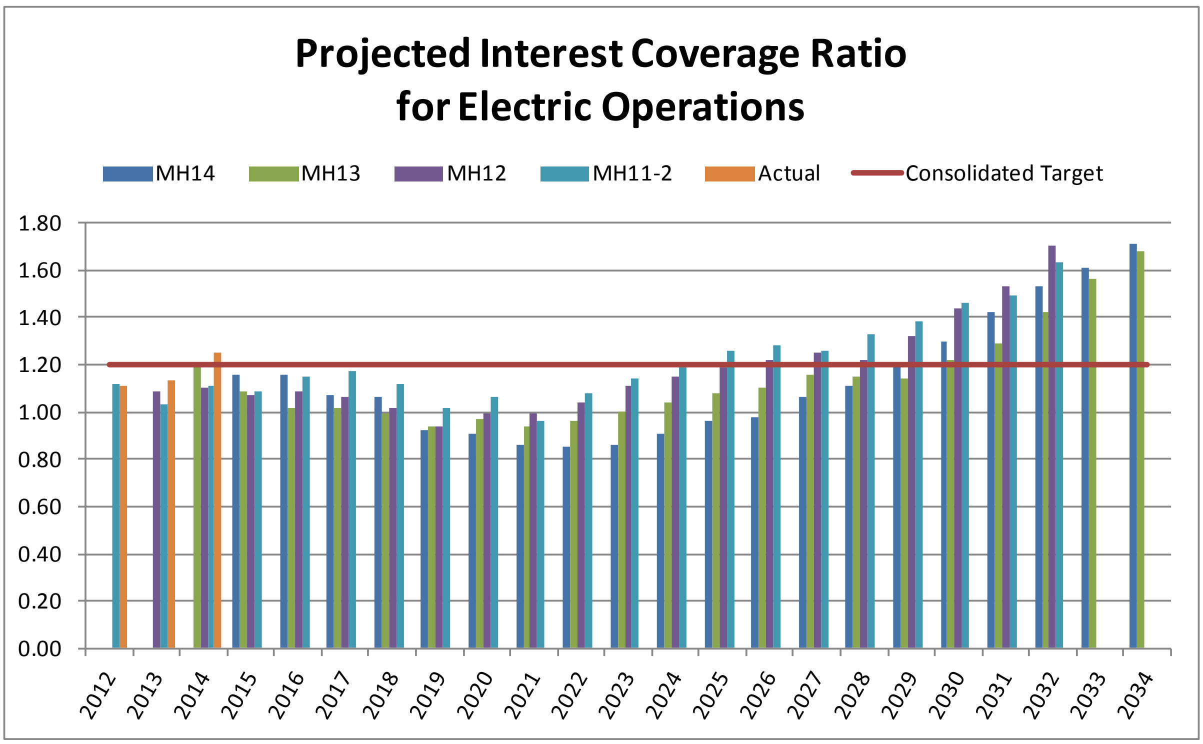
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	10%	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
MH13	10%	10%	10%	11%	11%	12%	13%	15%	18%	21%	24%
MH12	10%	10%	11%	13%	14%	15%	18%	20%	24%		
MH11-2	13%	14%	15%	17%	19%	21%	23%	26%	29%		
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%



Interest Coverage Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
MH14				1.16	1.16	1.07	1.06	0.92	0.91	0.86	0.85	0.86
MH13			1.20	1.09	1.02	1.02	0.99	0.94	0.97	0.94	0.96	1.00
MH12		1.09	1.10	1.07	1.09	1.06	1.02	0.94	0.99	0.99	1.04	1.11
MH11-2	1.12	1.03	1.11	1.09	1.15	1.17	1.12	1.02	1.06	0.96	1.08	1.14
Actual	1.11	1.13	1.25									
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

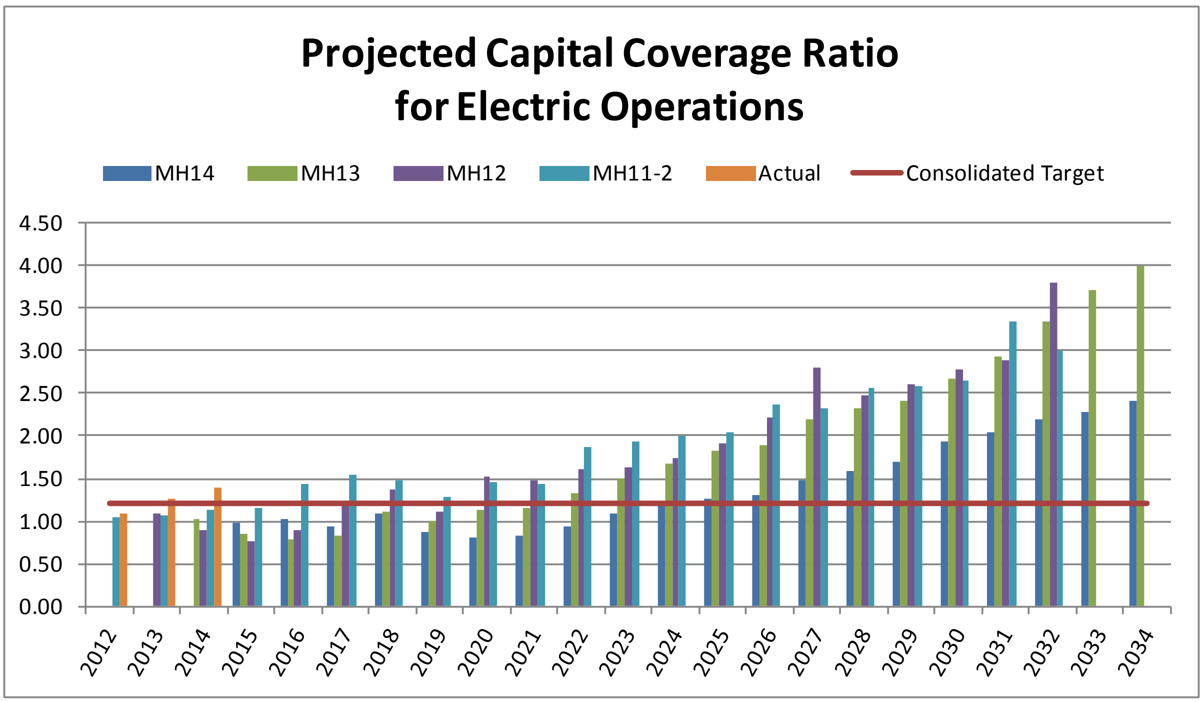
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	0.91	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
MH13	1.04	1.08	1.10	1.16	1.15	1.14	1.22	1.29	1.42	1.56	1.68
MH12	1.15	1.19	1.22	1.25	1.22	1.32	1.44	1.53	1.70		
MH11-2	1.19	1.26	1.28	1.26	1.33	1.38	1.46	1.49	1.63		
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



Capital Coverage Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
MH14				0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09
MH13			1.03	0.86	0.78	0.84	1.12	1.01	1.14	1.16	1.32	1.51
MH12		1.09	0.89	0.77	0.90	1.21	1.37	1.11	1.53	1.49	1.61	1.63
MH11-2	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46	1.43	1.86	1.93
Actual	1.10	1.26	1.39									
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	1.22	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41
MH13	1.68	1.82	1.89	2.20	2.33	2.40	2.68	2.94	3.34	3.72	3.99
MH12	1.75	1.91	2.21	2.80	2.47	2.60	2.77	2.88	3.80		
MH11-2	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00		
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that for the same period as requested in part (a) sets out the debt levels (as defined for purposes of the debt/equity ratio calculation) for each year based on IFF11-2, IFF12, IFF13 and IFF14.

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

Please see the following table.

Net Debt*
(in millions of $)

	IFF14	IFF13	IFF12	IFF11-2
2012				8,847
2013			9,673	9,701
2014		10,451	11,124	10,779
2015	11,729	11,960	12,801	12,092
2016	13,739	13,896	14,467	13,564
2017	16,346	15,916	16,236	15,019
2018	19,037	17,899	17,976	16,838
2019	20,862	19,556	19,441	17,955
2020	22,012	21,120	20,619	19,233
2021	22,688	22,009	21,884	20,584
2022	22,982	23,125	23,518	21,605
2023	23,142	24,731	24,980	22,322
2024	23,205	26,274	26,099	22,839
2025	23,227	27,545	26,939	23,388
2026	23,224	28,651	27,418	23,142
2027	23,091	29,385	27,598	22,733
2028	22,867	29,599	27,217	22,309
2029	22,537	29,467	26,848	21,960
2030	22,048	29,002	26,218	21,449
2031	21,453	28,297	25,367	20,763
2032	20,761	27,235	24,158	19,879
2033	20,019	25,908		
2034	19,238			

*Net Debt = Long term and short term debt net of debt for gas operations and short term and sinking fund investments

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that for the same period as requested in part (a) sets out the sum of Net Fixed Assets In-Service plus Assets Under Construction for each year based on IFF11-2. IFF12, IFF13 and IFF14.

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

Please see the following table.

Net Assets*
($ Millions)

	IFF14	IFF13	IFF12	IFF11-2
2012				11,321
2013			12,309	12,143
2014		13,228	13,777	13,291
2015	14,744	14,863	15,446	14,571
2016	16,832	16,880	17,160	16,152
2017	19,490	18,985	18,980	17,765
2018	22,175	20,878	20,724	19,697
2019	23,727	22,424	22,107	20,812
2020	24,474	23,670	23,190	22,050
2021	24,969	24,322	24,305	23,287
2022	24,977	25,434	26,004	24,435
2023	24,998	27,101	27,662	25,392
2024	25,004	28,800	29,061	26,236
2025	25,047	30,290	30,255	27,223
2026	25,081	31,657	31,135	27,457
2027	25,103	32,769	31,786	27,496
2028	25,103	33,352	31,834	27,614
2029	25,106	33,576	32,070	27,890
2030	25,077	33,620	32,216	28,108
2031	25,075	33,545	32,272	28,217
2032	25,068	33,314	32,179	28,243
2033	25,088	33,035		
2034	25,176			

*Property, Plant and Equipment and Construction in Progress, net of Accumulated Depreciation

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page 14, lines 12-16, since the calculation of the interest coverage ratio includes interest capitalized in both the numerator and the denominator and does not take into account cash flow from depreciation, please explain how a value of less than 1.0 indicates the utility would: i) experience elevated operational liquidity risk and ii) potential difficulty generating sufficient revenues and cash from operations to pay interest obligations.

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

Directionally, the lower the interest coverage ratio, the greater the operational liquidity risk that the Corporation will have insufficient cash flow from operations to meet its sustaining expenditures and financial obligations.

Manitoba Hydro's interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. The ratio is calculated as net income plus gross interest expense, with this sum divided by gross interest expense. Gross interest (which is in both the ratio's numerator and denominator) is before any adjustment for capitalized interest. Net income (which is only in the ratio's numerator) excludes the capitalized interest but includes depreciation expense (which is a partial proxy for the cash flow required to replace depreciating assets and fund sustaining capital expenditures).

Annual interest coverage at or greater than 1.20 provides a margin of earnings in excess of that which is required to cover interest payments to bondholders. If the interest coverage ratio is below 1.00, the risk of cash shortfalls from operations becomes serious, especially if there are other adverse circumstances such as a drought.

Manitoba Hydro's interest coverage ratio is forecast to be well below target for several years of the forecast. In eight years of the forecast, Manitoba Hydro's interest coverage ratio is below 1.00. In these circumstances, in order to maintain the same level of sustaining expenditures and customer service, there is elevated risk that Manitoba Hydro would need to secure additional debt – thereby increasing finance expense and ultimately raising customer rates.

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page 14, line 21, please provide a schedule that sets out the capital cost of Bipole III as used in IFF11-2, IFF12, IFF13 and IFF14 and explain any material variances.

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

Please see the response to PUB/MH I-20a for a comparison of the capital cost of Bipole III from CEF12 to CEF14 and an explanation of material variances. Please note that the capital cost for Bipole III in CEF11-2, CEF12 and CEF 13 forecasts are all $3.28 billion.

Section:	Tab 3	Page No.:	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page 14, line 21, please provide a schedule that sets out the capital cost of Keeyask as used in IFF11-2, IFF12, IFF13 and IFF14 and explain any material variances

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

The table below provides a comparison of the capital cost of Keeyask Generating Station from CEF13 to CEF14, as well as between CEF12 and CEF11-2 consistent with Figure 4.8 of the Application. The total capital cost of $6.2 billion is the same in both CEF12 and CEF13. However, there are small variations between categories which are discussed below.

Keeyask Generating Station - Continuity Schedule of CEF 11-2 through CEF 14 Budgets
(in millions $)

Cost Breakdown (in millions of dollars)	CEF 11-2	CEF 12		CEF 13	CEF 14
Generating Station (Including GCC and KIP)	2 756.1	2 969.9		3 060.1	3 657.9
Construction Power	21.8	29.2		30.4	30.4
Licensing & Planning	374.5	394.8		397.3	393.0
Transmission (excluding contingency)	118.5	138.0		138.3	142.1
Contingency & Management Reserves	573.1	1 046.9		1 063.7	685.2
Interest & Escalation	1 792.9	1 641.3		1 530.3	1 587.5
TOTAL	**5 636.9**	**6 220.1**		**6 220.1**	**6 496.1**

Note: Sunk Costs are included in each project component

Comparison of CEF13 to CEF14

The increase to the project cost of Keeyask for CEF14 versus the previous approved amount has been driven by several factors as discussed below:

Incorporation of Awarded Contract Amounts

The largest contract on the Keeyask Project is the General Civil Contract, which has now been awarded, and the awarded value is incorporated into the CEF14. The awarded value is greater than previous estimates, due in part to current market conditions. In addition, the awarded value of direct negotiated service contracts is greater than previous estimates.

Incorporation of Post-construction Adverse Effects

The budget was revised to incorporate the present value of post-construction adverse effect payments.

Finalization of Keeyask Infrastructure Project, Finalization of Construction Management Delivery Strategy, and Updated Estimates

The construction of the Keeyask Infrastructure Project was entering its final stages when CEF14 was established. There was an overall increase in construction costs, in part to reflect unforeseen site conditions. In addition, the construction management delivery strategy for the Generating Station Project was revised to incorporate staff augmentation by a consultant, where required. There was an overall increase in miscellaneous estimates, including stage 5 engineering, interface management, forebay clearing, environmental monitoring, and social mitigation.

Changes to Contingency and Management Reserves:

A complete risk and contingency review was conducted as part of establishing the revised control budget for the project. The risk identification and contingency development process was presented during the NFAT process. A revised P50 contingency and Management Reserve fund were developed at that time.

Increase in Capitalized Interest:

Capitalized interest in the project budget has increased since the last approved budget which has resulted from the change in base costs mentioned in the above categories as well as changes in cash flows. Interest has the potential to change the control budget significantly and will be continuously evaluated over the life of the project.

Comparison of CEF12 to CEF13

The change between CEF12 and CEF13 is primarily due to the reallocation of escalation to the Generating Station category, revising the estimate to reflect 2013 dollars.

Comparison of CEF11-2 to CEF12

The increase to the project cost of Keeyask for CEF12 versus CEF11-2 was driven by several factors as discussed below:

Inclusion of Labour & Escalation Management Reserve

A labour reserve was added to reflect potential additional costs associated with higher risk in labour productivity and cumulative impacts. An escalation reserve was added to reflect potential additional costs associated with cost escalation greater than Canadian Consumer Price Index (CPI).

Camp Accommodation Upgrade

The scope for the main construction camp was changed to be in-line with industry-style camps in order to reduce employee turnover at site and to attract and retain the work force.

Increase for licensing and planning costs

There were additional adverse effects payments added resulting from associated agreements, increased regulatory and environmental activities largely resulting from sturgeon (SARA), sturgeon stewardship and First Nation interests, additional First Nation labour, field training and disbursements for studies as well as increased costs for EIS preparation.

Detailed scope for Transmission Lines & Stations

The transmission line underwent more detailed scoping which identified the number and types of towers required as well as addition of line from the Generating Station to switching station. The transmission stations also underwent more detailed scoping which identified breaker replacements and bank addition requirements.

Changes to Interest and Escalation

The base dollars in the budget increased overall due to escalating the estimate from 2009 to 2012$, partially offset by a reduction to forecasted escalation. Capitalized interest decreased as a result of a reduction to forecasted interest rates.

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With reference to page 14 (lines 21-22), please provide a schedule that sets out the annual spending for the years 2011/12 through 2031/32 for i) DSM and ii) the renewal and replacement of aging infrastructure as forecast in IFF11-2, IFF12, IFF13 and IFF14. Where appropriate please include the actual spending values in the schedule.

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

The following tables set out the forecasted and actual annual spending for DSM and Sustaining Capital (Major and Base Capital).

	DSM Spending ($ Millions)					Sustaining Capital ($ Millions)				
	Actual	**MH14**	**MH13**	**MH12**	**MH11-2**	**Actual**	**MH14**	**MH13**	**MH12***	**MH11-2***
2012	27				32	465				417
2013	27			29	34	433			434	412
2014	26		28	28	34	470		526	544	394
2015		52	25	25	31		571	637	575	387
2016		59	25	24	31		577	631	530	364
2017		77	24	23	28		610	632	414	372
2018		84	23	22	24		547	468	358	380
2019		94	22	22	23		547	474	408	388
2020		78	20	20	21		548	477	348	396
2021		73	19	19	21		573	481	404	360
2022		61	19	19	21		555	484	440	386
2023		50	19	19	21		563	487	513	430
2024		50	19	19	21		571	493	534	462
2025		48	19	19	22		621	493	531	523
2026		48	18	18	17		624	499	500	499
2027		47	16	16	16		637	503	448	515
2028		47	16	17	17		649	508	512	503
2029		48	16	17	17		675	512	558	536
2030		50	17	17	17		665	520	592	568
2031		52	17	18	18		703	521	624	479
2032		54	17	18	18		711	526	536	584
2033		57	18				724	531		
2034		59					735			

* Includes IFRS OH Adjustment

Section:	Tab 3	**Page No.:**	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the response to part (g), please indicate (with reference to CEF14) what expenditures are considered to be associated with "aging infrastructure renewal and replacement".

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

Many infrastructure renewal and replacement projects are driven by a number of contributing factors with capacity and condition of plant due to aging infrastructure often important considerations to the replacement decision. Other factors that can contribute to the capital investment decision include safety to employees and the public, operational and environmental concerns etc. As a result, expenditures associated solely with aging infrastructure renewal and replacement cannot be separately identified within the CEF.

Section:	Tab 3	**Page No.:**	15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets – Capital Coverage		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the Capital Expenditure value used in the calculation of the Capital Coverage ratio includes all capital spending except for that associated with Major New Generation and Transmission projects (i.e., both categories (ii) and (iii) from above). If not, precisely what categories of capital spending are included for purposes of calculating the ratio?

RATIONALE FOR QUESTION:

Clarify the calculation of the Capital Coverage Ratio.

RESPONSE:

Confirmed. The capital coverage ratio calculation for Electric Operations only, which has been provided in the GRA, is calculated using the CEF14 Major & Base Capital Total less the Gas operations portion. Major New Generation and Transmission projects are excluded from the calculation.

Section:	Tab 3	**Page No.:**	15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets – Capital Coverage		

PREAMBLE TO IR (IF ANY):

QUESTION:

Does the Capital Expenditure value used in the determination of the capital coverage ratio include any capital spending associated with load growth (e.g., transmission network extensions, new substations or distribution facility extensions)?

RATIONALE FOR QUESTION:

Clarify the calculation of the Capital Coverage Ratio.

RESPONSE:

The capital expenditure value used in the determination of the capital coverage ratio includes capital spending associated with load growth. As discussed in Tab 4, electric load has grown in an increasing number of service areas and as such, the Corporation has identified a number of capital investment priorities for its distribution and transmission systems to address these capacity issues.

Section:	Tab 3	**Page No.:**	15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets – Capital Coverage		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the response to part (b) is affirmative, does the ratio really measure what is Manitoba Hydro defines as "sustaining" capital expenditures as suggested on Page 15 (lines 6-8)?

RATIONALE FOR QUESTION:

Clarify the calculation of the Capital Coverage Ratio.

RESPONSE:

The capital coverage ratio measures the ability of current period internally generated funds to finance sustaining capital expenditures excluding major new generation and transmission items. Sustaining capital includes items identified in CEF14 as either Major or Base capital expenditures and consists of additions, improvements and replacements of existing infrastructure. As discussed in part (b), additions to plant are required due to capacity constraints as a result of load growth, impacting system performance and customer growth.

Section:	Tab 3	**Page No.:**	5
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous IFF		

PREAMBLE TO IR (IF ANY):

Throughout IFF14 there are comparisons to IFF13

QUESTION:

Please provide copies of CEF13 and IFF13.

RATIONALE FOR QUESTION:

IFF14 and CEF14 are compared to the previous year's forecasts. Also, clarify the treatment of subsidiary revenues and costs in the various electric operations forecasts. This goes to the credibility of forecasts.

RESPONSE:

Please see the attached copies of CEF13 and IFF13.

February 2014

Integrated Financial Forecast (IFF13)

2013/14 - 2032/33

Financial Planning
Finance & Regulatory

Manitoba Hydro

Manitoba Hydro

INTEGRATED FINANCIAL FORECAST (IFF13)

2013/14 – 2032/33

FINANCIAL PLANNING DEPARTMENT
FINANCE & REGULATORY

February, 2014

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INTEGRATED FINANCIAL FORECAST (IFF13)

KEY FINANCIAL RESULTS

(Dollars are in millions)

	Actual	IFF13 Forecast			
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2022/23**
PROJECTED RATE INCREASES					
- ELECTRIC	4.50%[1]	3.50%[2]	3.95%	3.95%	3.95%
- GAS (non-commodity)	-	1.07%	-	0.50%	0.00%
NET INCOME					
- ELECTRIC	$ 78	$ 116	$ 55	$ 12	$ 6
- GAS	8	12	1	4	3
- SUBSIDIARIES	6	8	6	8	12
CAPITAL EXPENDITURES					
- ELECTRIC	$ 1 033	$ 1 597	$ 2 013	$ 2 422	$ 2 280
- GAS	39	49	48	61	38
DEBT/EQUITY RATIO	75:25	76:24	78:22	82:18	89:11
INTEREST COVERAGE RATIO	1.15	1.22	1.09	1.03	1.01
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.25	1.06	0.87	0.80	1.52
RETAINED EARNINGS	$2 542	$ 2 678	$ 2 739	$ 2 705	$2 575

[1] Includes a 2.0% rate increase effective April 1, 2012 and a 2.5% rate increase effective September 1, 2012.

[2] The 3.5% rate increase was implemented effective May 1, 2013. In accordance with PUB Order 43/13, 1.5% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

EXECUTIVE SUMMARY

The Consolidated Integrated Financial Forecast (IFF13) projects Manitoba Hydro's financial results and financial position for the 20-year period from 2013/14 to 2032/33. Segmented forecasts are also provided for the electricity (MH13), natural gas (CGM13), and corporate subsidiaries (CS13).

Financial results projected in IFF13 are less favourable than the financial results projected in IFF12. The projection of less favourable results is largely attributable to the following:

- Lower projected net revenue ($1.0 billion) due to lower projected domestic Manitoba load somewhat offset by higher net extra-provincial revenue; and
- Higher projected capital costs ($1.6 billion) due to the one year deferral of the Conawapa Generating Station, the re-instatement of Electric and Gas demand side management costs in the capital forecast and the update of a number of project cost estimates.

IFF13 includes further internal cost constraint provisions to mitigate the rate pressures as a result of the reduction in net revenue and capital requirements. These initiatives assist in offsetting the incremental rate impacts and therefore the projected even annual electric rate increases in IFF13 for each year up to 2031/32 are the same as projected in IFF12 at 3.95%, with one more additional year of 3.95% in 2032/33.

Consistent with IFF12, the equity ratio is reduced from the current 24% level to 11% equity by 2021/22 before gradually beginning to recover to reach the 25% equity target by 2033/34. This represents a two year deferral in attaining the 25% equity target compared to IFF12.

The other key financial targets – interest coverage and capital coverage – are also below target for several years but recover to the target range within the later years of the 20 year forecast.

Notwithstanding the changes in the projected financial results, Manitoba Hydro's proposed major capital expansion program remains as the best plan to meet the future electricity requirements of the Province in the most reliable, economic and environmentally sustainable way. While rate increases that are higher than inflation will be necessary to maintain a reasonable financial structure, the revenue generated by those rate increases will, in part, represent an investment in the future of the Province. This investment will pay dividends to current and future generations of Manitobans over the approximate 100-year service lives of the new generation and transmission facilities.

Also contributing to the need for higher rate increases is the requirement to replace distribution, transmission and substation assets that were installed up to 60 years ago. The aging infrastructure issue is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the rate increases being projected in IFF13, it is expected that

Manitoba Hydro will maintain its status as having the lowest overall rate structure in North America.

The following is a summary of projected net income and key financial ratios over the 20-year period to 2032/33:

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2014	-	$136	$2 678	76:24	1.22	1.06
2015	3.95%	62	2 739	78:22	1.09	0.87
2016	3.95%	24	2 705	82:18	1.03	0.80
2017	3.95%	31	2 736	84:16	1.03	0.87
2018	3.95%	(0)	2 736	85:15	1.00	1.17
2019	3.95%	(55)	2 681	86:14	0.95	1.07
2020	3.95%	(19)	2 662	87:13	0.98	1.18
2021	3.95%	(62)	2 600	88:12	0.95	1.20
2022	3.95%	(45)	2 555	89:11	0.97	1.35
2023	3.95%	20	2 575	89:11	1.01	1.52
2024	3.95%	82	2 658	89:11	1.05	1.68
2025	3.95%	148	2 806	89:11	1.09	1.79
2026	3.95%	184	2 990	89:11	1.10	1.86
2027	3.95%	297	3 287	89:11	1.16	2.14
2028	3.95%	293	3 579	88:12	1.15	2.27
2029	3.95%	275	3 854	87:13	1.14	2.32
2030	3.95%	425	4 280	86:14	1.22	2.59
2031	3.95%	550	4 830	84:16	1.29	2.81
2032	3.95%	760	5 589	82:18	1.42	3.18
2033	3.95%	970	6 560	78:22	1.56	3.53

Section 1

1.0 INTRODUCTION

The Consolidated Integrated Financial Forecast (IFF13) provides projections of Manitoba Hydro's financial results and financial position for the 20-year period from 2013/14 to 2032/33. Its purpose is to project the Corporation's long-term financial direction and to serve as a baseline for the evaluation of Corporate Strategic Initiatives.

The detailed forecasts in the first two years of the IFF are used for monthly reporting and variance analysis. The IFF serves as the primary forecast to determine the need for rate increases that are necessary for the Corporation to attain its financial targets and objectives.

The forecast is the culmination of an extensive integrated planning cycle at Manitoba Hydro. It is based on the best available information at the time it is prepared and includes forward looking information that incorporates expectations, estimates and assumptions concerning the future which are subject to change. Key inputs to the Integrated Financial Forecast include:

- Economic Outlook
- Energy Price Outlook
- Electricity Export Price Forecast
- Power Smart Plan
- Electric Load Forecast
- Natural Gas Volume Forecast
- Domestic Revenue Forecast
- Power Resource Plan
- Generation Costs and Interchange Revenue Forecast
- Capital Expenditure Forecast
- Operating, Maintenance & Administrative Expense Forecast

This forecast supersedes the 2012 Integrated Financial Forecast (IFF12) which was finalized in November of 2012.

2.0 RATES and ECONOMIC VARIABLES

2.1 Electricity Rates

In accordance with Manitoba Public Utilities Board (PUB) Order 43/13, IFF13 assumes that 1.5% of the 3.5% Electric rate increase that was approved effective May 1, 2013 will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in service. IFF13 further assumes that the 1.5% of the rate increase will continue to accrue until the time when Bipole III is placed in service (October 2017) and that the cumulative amount in this deferral account will be amortized to income over a three year period thereafter. After the Bipole III in-service date, the 1.5% rate increase will revert to general consumers revenue.

Additional average electric rate increases of 3.95% per year are projected each April from 2014/15 through 2032/33.

The rate increase proposed for 2014/15 has been approved by the Manitoba Hydro-Electric Board (MHEB) for submission to the PUB. Proposed rate increases subsequent to 2014/15 may be changed in future forecasts and are presented for illustrative purposes only. Each year's revision to the Integrated Financial Forecast is based on the current year's assumptions including energy supply and demand, projected interest and escalation rates, projected prices for exported energy, operating and capital forecasts and other factors. Changes in any of these assumptions will have an impact on the projected future results. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

2.2 Gas Rates

There is no non-gas rate increase proposed for the 2014/15 fiscal year. IFF13 assumes non-gas rate increases commencing on May 1, 2015 sufficient to generate Centra Gas net income of approximately $3 million each year beginning in 2015/16 and thereafter. Gas general rate applications are also subject to review and approval by the MHEB prior to filing with the PUB.

2.3 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of November 2013 to reflect current economic conditions at that time. Projected rates for key economic indicators are listed below with the 2012 projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	US-CDN Exchange Rate (C$/US$)
2013/14	1.8% (1.8%)	1.00% (1.30%)	3.75% (3.30%)	1.04 (0.99)
2014/15	2.0% (1.8%)	1.15% (2.10%)	4.05% (3.85%)	1.03 (1.02)
2015/16	2.0% (1.8%)	2.10% (2.95%)	4.35% (4.55%)	1.01 (1.03)
2016/17	2.0% (1.8%)	3.10% (3.65%)	4.60% (4.95%)	1.01 (1.04)
2022/23	2.0% (1.9%)	3.90% (3.80%)	5.75% (5.30%)	1.03 (1.04)

* Excludes the 1% Provincial guarantee fee.

3.0 Manitoba Electricity Load Forecast

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2013 Electric Load Forecast.

The 2013 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.5% for both gross firm energy and gross total peak over the 20-year forecast period to 2032/33 (compared to 1.6% in IFF12). Gross firm energy supplied to the Manitoba load is projected to grow from 25 239 GW.h in 2013/14 to 32 667 GW.h by 2032/33. Over the same 20-year period, total system peak is projected to grow from 4 601 MW in 2013/14 to 5 959 MW in 2032/33. The system load factor is projected to remain relatively constant at approximately 63%.

Compared to the 2012 forecast, gross firm energy is 495 GW.h lower in 2013/14 due mainly to lower forecasted industrial and general service loads. Gross firm energy is projected to be down 717 GW.h in 2022/23 and 1 159 GW.h in 2031/32 primarily due to a decrease in the forecast of residential customers resulting from a lower Manitoba population growth rate and initiatives being undertaken to reduce the number of customers choosing electric space and water heat. The gross total peak forecast is 8 MW lower in 2013/14 and 146 MW lower than the 2012 forecast in 2031/32, for similar reasons to the change in energy.

This reduced load translates to a reduction in General Consumer Revenue of $1 185 million to the end of 2032/33 at IFF12 forecasted rates.

4.0 Extra-provincial Revenue

IFF13 includes the following existing and proposed long-term firm export sales:

Northern States Power 150 MW Seasonal Diversity	To April 2015
Northern States Power 200 MW Seasonal Diversity	To April 2016
Northern States Power 500 MW Power Sale	To April 2014
Minnesota Power 50 MW System Participation Sale	May 2009 to April 2015
Minnesota Power 50 MW System Participation Sale*	May 2015 to May 2020
Minnesota Power 250 MW System Participation Sale	June 2020 to May 2035
Great River Energy 150 MW Seasonal Diversity Sale	May 1995 to April 2015
Great River Energy 200 MW Seasonal Diversity Sale	May 2015 to April 2025
Northern States Power 125 MW System Power Sale	May 2021 to April 2025
Northern States Power 375/325 MW System Power Sale	May 2015 to April 2025
Northern States Power 350 MW Seasonal Diversity Sale	May 2015 to April 2025
Wisconsin Public Service 100 MW Sale	June 2021 to May 2027
Wisconsin Public Service 300 MW Term Sheet Sale*	June 2026 to May 2036
Wisconsin Public Service 108 MW System Participation*	June 2014 to May 2021
Wisconsin Public Service 200 MW System Participation*	June 2020 to May 2026 June 2036 to May 2040

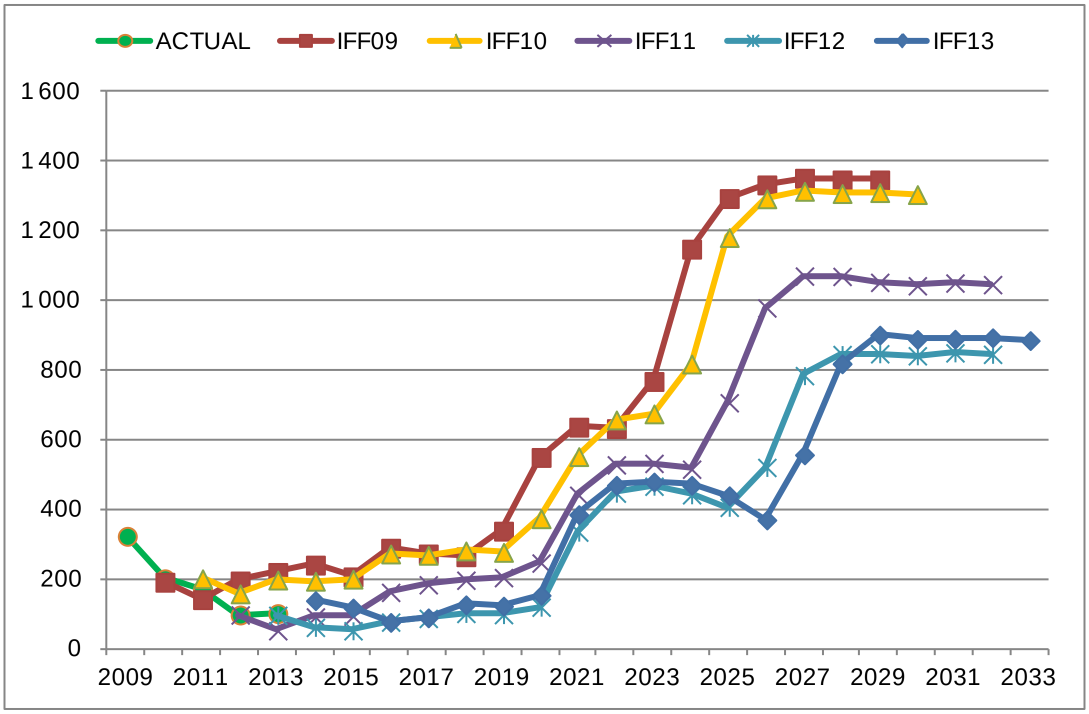
* Proposed

Extra-provincial sales volumes are forecast for the first forecast year (2013/14) based upon the expected inflow conditions as of December 2013 and actual reservoir and lake level elevations as of November 2012. The second forecast year (2014/15) uses the expected river inflows and initial reservoir and lake level elevations carried forward from the 2013/14 forecast. For 2015/16 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 99 years (1912/13 to 2010/11).

Over the twenty year forecast period, net extra-provincial revenue (extra-provincial revenue net of water rentals and fuel and power purchased) increases $203 million compared to IFF12. The increase is mainly due to higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast, partially offset by decreased volumes associated with the deferral of the Conawapa Generating Station in-service date by one year to 2026/27. Figure 4-1: Extra-provincial Revenues below shows the comparative net extra-provincial revenues from IFF09 through IFF13.

Figure 4-1: Extra-provincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



In comparison to the 2012 Electric Export Price Forecast, the 2013 forecast projects on-peak prices to decrease on average 3% over the period 2014/15 to 2032/33. The small decrease reflects the forecast for lower natural gas prices, somewhat offset by the stabilizing effects of relatively flat year over year coal and carbon price forecasts along with upward pressure on prices being provided by clarity on US environmental regulation and resulting coal fleet retirements.

5.0 Electricity Supply

Manitoba Hydro's 2013/14 Power Resource Plan indicates new generation is required by 2023/24 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2026/27.

The following resources contribute to the ability to meet future Manitoba energy and capacity requirements.

	MW	Dependable GW.h	In-Service Date
Keeyask	695	2 900	2019/20
Conawapa	1 485	4 550	2026/27
HVDC Bipole III Line & 2000 MW of Converter Capability	86	190	2017/18
Pointe du Bois Powerhouse Rebuild	45	150	2030/31
Demand Side Management Program			
Planned Additional	166	773	By 2027/28

6.0 International Financial Reporting Standards (IFRS)

In February of 2013, the Canadian Accounting Standards Board (AcSB) extended the optional IFRS transition date for rate-regulated entities an additional year to January 1, 2015 in consideration of the commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting.

In April of 2013, the IASB issued the Exposure Draft – Regulatory Deferral Accounts. The Exposure Draft proposed an interim standard intended to allow entities that are first-time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. The IASB finalized the interim standard on January 30, 2014. Under the interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. While it is uncertain as to the final position the IASB will take as part of its Rate regulated Activities project, it has been assumed in IFF13 that regulatory deferral accounts will continue to be recognized throughout the forecast period to 2032/33.

Manitoba Hydro will adopt the optional transition date deferral and will be transitioning to IFRS for its 2015/16 fiscal period with comparative information presented for 2014/15.

The primary impacts of IFRS that are included in IFF13 are as follows:

- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred;
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates; and

- Unamortized experience gains and losses on pension balances will be reclassified to accumulated other comprehensive income (AOCI) upon transition to IFRS.

The following table Figure 6-1 outlines the projected IFRS impacts to retained earnings, AOCI and net income:

Figure 6-1: IFRS Impacts on Retained Earnings and Net Income

Increase/(Decrease)
($Millions)

	Retained Earnings	AOCI	Net Income 2015/16
Capital Taxes	-	-	2
Administrative Overhead *	(53)	-	(53)
Pension & Employee Benefits	(30)	(332)	6
Removal of Negative Salvage	62	-	64
Change to Equal Life Group Depreciation	(36)	-	(37)
Total	(57)	(332)	(18)

*Impacts to net income are net of depreciation & amortization.

7.0 Operating & Administrative Expense

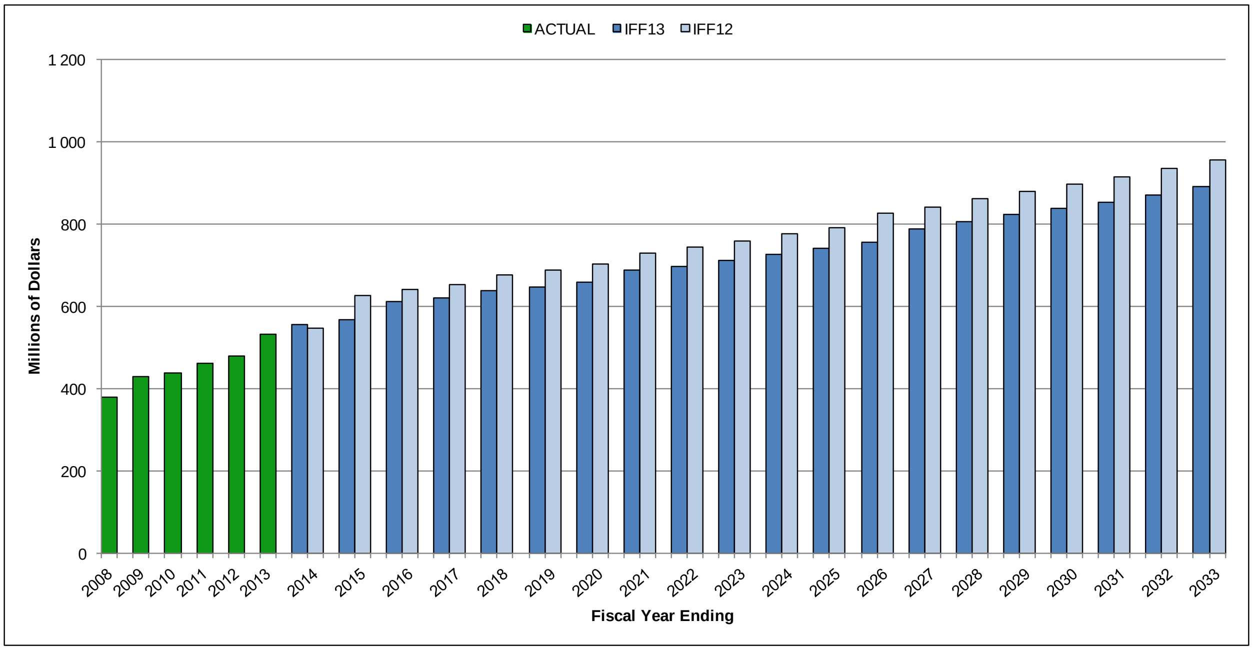
Operating, Maintenance & Administrative (OM&A) Expenses in IFF13 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and electric and gas distribution systems.

Figure 7-1 below shows the OM&A expense projected in IFF13 compared to IFF12. Over the 10 year period to 2022/23, OM&A is projected to decrease by approximately $37 million annually on average compared to IFF12 primarily due to the assumption in IFF13 that regulatory deferral accounts will continue to be recognized throughout the forecast period. This decrease is partially offset by an increase in the amount of administrative and other general overhead costs that must be expensed under IFRS from $39 million to $54 million.

IFF13 also incorporates the deferral of IFRS implementation to 2015/16 as discussed in Section 6.0 which results in the reduction in OM&A that can be seen in 2014/15 compared to IFF12.

For the period from 2015/16 to 2020/21, it is assumed that OM&A cost increases will be limited to below inflationary levels of 1%. For the remainder of the forecast, O&A rises at the same level as inflation except in years where major new generation and transmission comes into service in 2017/18 (Bipole III), 2019/20 (Keeyask), 2020/21 (500kV tie line) and 2026/27 (Conawapa). Increases associated with load growth over the forecast period are assumed to be achieved through continuing productivity improvements.

Figure 7-1: Operating, Maintenance and Administrative Expense



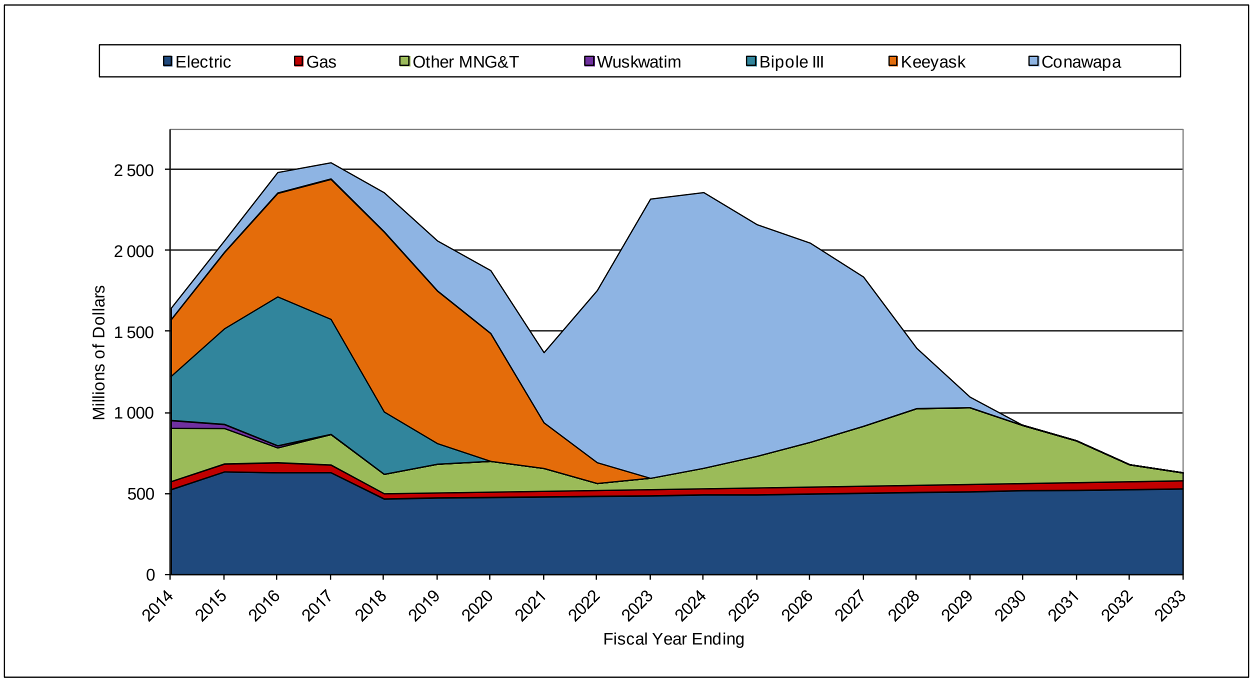
8.0 Non-Controlling Interest

IFF13 assumes that the Nisichawayasihk Cree Nation (NCN) will acquire up to a 33% common equity interest in the Wuskwatim Power Limited Partnership (WPLP) and that the Keeyask Cree Nations (KCN) invest in the Keeyask Hydropower Limited Partnership (KHLP) under a preferred equity ownership arrangement. The Non-controlling interest represents NCN's share of the projected net income or losses in WPLP and the projected distributions paid from the KHLP to KCN. Manitoba Hydro will construct, operate and maintain the Wuskwatim and Keeyask generating stations and will purchase all of the output under power purchase agreements with the respective partnerships. Manitoba Hydro's income statement reflects all of the partnership revenues and costs with NCN's share of net income or losses and KCN's share of distributions shown as a deduction before net income. The partnerships' net assets are offset by an amount for NCN's and KCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

9.0 CAPITAL EXPENDITURE FORECAST

Capital expenditures are forecast to be $34 442 million to 2032/33. Figure 9-1 below illustrates projected capital expenditures by major category.

Figure 9-1: Capital Expenditure Forecast CEF13



Over the 20-year forecast to 2032/33, capital expenditures are $1 629 million higher compared to the previous capital expenditure forecast (CEF12) including the overhead adjustment incorporated in IFF12. The increase is mainly the result of the one year deferral of the Conawapa Generating Station to 2026/27, the re-instatement of Electric and Gas Demand Side Management costs in the forecast under the assumption that regulatory deferral accounts will continue to be recognized upon transition to IFRS and the update of a number of project cost estimates (see Table 9-2). The following Table 9-1 provides a summary of CEF13 and the revisions from CEF12.

Table 9-1: Summary of Projected Capital Expenditures

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
CEF12	1 895	2 042	2 112	2 258	2 219	1 913	1 718	1 854	2 356	2 323	20 689
Incr (Decr)	(248)	20	371	285	140	148	160	(482)	(601)	(4)	(211)
CEF13	1 647	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	20 478

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
CEF12	2 077	1 883	1 615	1 471	928	1 127	1 047	994	859	834	33 526
Incr (Decr)	282	279	432	367	470	(29)	(125)	(166)	(179)	(204)	916
CEF13	2 359	2 162	2 048	1 838	1 399	1 098	922	828	680	630	34 442

The following Table 9-2 provides a summary of the total changes to the twenty year forecast.

Table 9-2: Summary of CEF13 Project Increases/(Decreases)

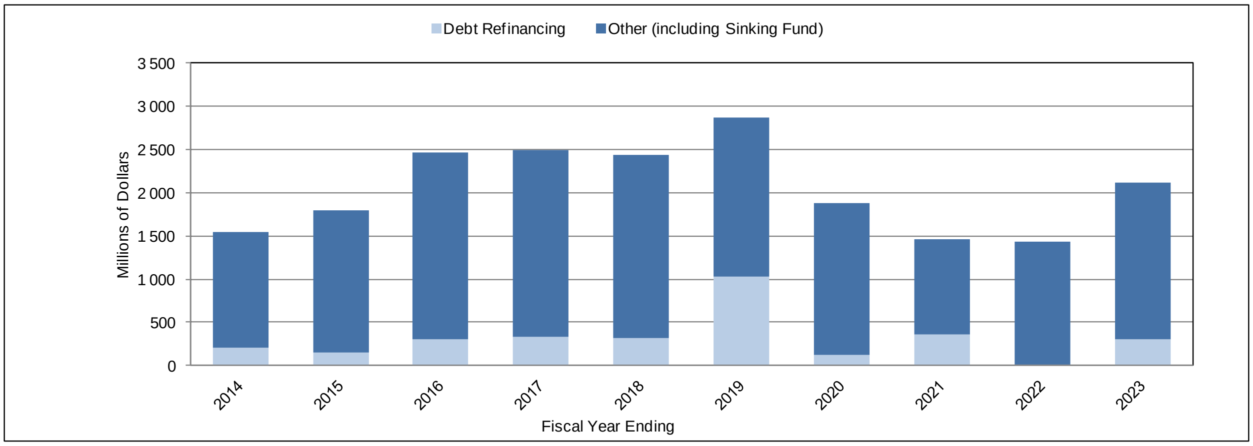
	Total Projected Cost	20 Year Increase (Decrease)
	($ Millions)	
Electric Demand Side Management*	NA	367
Conawapa - Generation	10 492	324
Transmission Line Upgrades for NERC Alert	151	151
Dorsey - US Border New 500kV Transmission Line	350	146
Electric Base Capital	NA	136
Gas Demand Side Management*	NA	71
Keeyask - Generation	6 220	64
Bipole III - Converter Stations	1 829	63
Riel 230/500kV Station	330	63
Community Development Initiative	61	61
Pointe du Bois Spillway Replacement	560	60
Wuskwatim - Generation	1 449	52
Dawson Road Station - 115/24kV Station	52	52
St. Vital Station - 115/24kV Station	51	51
Gas Base Capital	NA	45
Other Changes	NA	(77)
Sub-total		1 629
CEF12 Overhead Adjustment	NA	(713)
		916

*Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under the interim standard that continues to permit rate-regulated accounting.

10.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 10-1 below.

Figure 10-1: Projected Consolidated Borrowing Requirements



Manitoba Hydro arranges long-term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the Manitoba Hydro-Electric Board). Manitoba Hydro's target range is to hold 15% to 25% of debt in floating rate instruments in order to minimize debt costs without undue interest rate exposure.

11.0 NATURAL GAS DEMAND & SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 94% of customers representing approximately 61% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The volume forecast incorporates Manitoba Hydro's Fixed Price Offering for primary gas, which was introduced in 2008/09 and offers customers one, three, and five-year fixed price contracts.

The forecast incorporates the transportation and supplementary gas requirements, not only for Manitoba Hydro's customers but also for those consumers who purchase their primary gas from brokers and marketers.

The 2013 Natural Gas Volume Forecast is lower than last year's forecast. The total natural gas sales volume forecast is down 20 million cubic meters (1%) in 2013/14 and down 3 million cubic meters (0.1%) in 2022/23. The decrease in the 2013 forecast is primarily attributed to a change in the expected usage of the Top Consumer groups.

12.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

Debt/Equity Ratio	Achieve and maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting major new generation and transmission)

Financial targets may not be achieved during years of major investment in the generation and transmission system.

12.1 Debt/Equity Ratio

The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Figure 12-1 below shows the projected consolidated equity ratio for IFF13 compared to IFF12. High levels of capital investment over the next ten years combined with reduced revenues result in deterioration of the equity ratio to 11% by 2021/22. The equity ratio shows improvement following the in-service of Keeyask and Conawapa generating stations and is projected to return to the target 25% within one year (2033/34) of the 20-year forecast period.

Figure 12-1: Projected Consolidated Equity Ratio

12.2 Interest Coverage Ratio

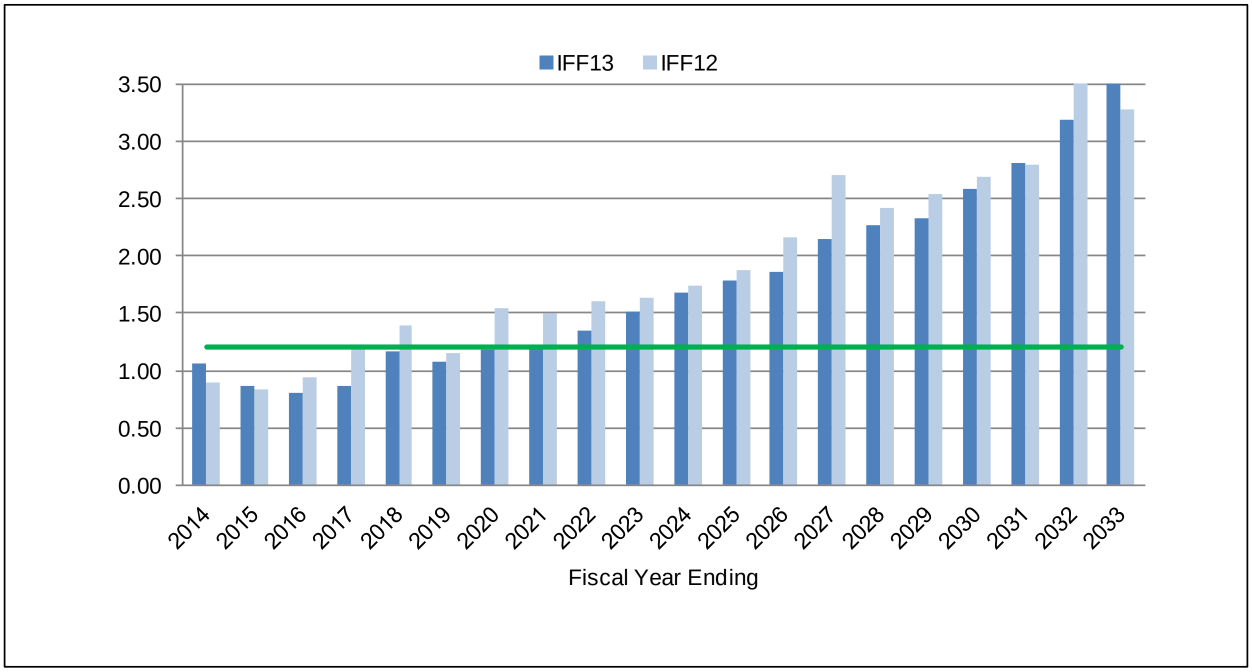
The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 12-2 below shows that the reduction in net income compared to the previous forecast IFF12 and increase in capital requirements to replace aging infrastructure results in interest coverage ratios lower than target for a period of fifteen years. In the longer term, interest coverage is projected to return to the 1.20 target level following in-service of the Conawapa Generating Station.

Figure 12-2: Projected Consolidated Interest Coverage Ratio

12.3 Capital Coverage Ratio

The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Figure 12-3 below shows the comparative capital coverage ratios between IFF13 and IFF12. Capital coverage is below target for the first seven years of the forecast and then projected cash flows are sufficient to enable this target to be met in the remaining years of the forecast after the in-service of the Keeyask Generating Station.

Figure 12-3: Projected Consolidated Capital Coverage Ratio



13.0 SENSITIVITY ANALYSIS

The 20-Year Financial Outlook includes a number of key assumptions as described in the previous sections. A change to one or more of those assumptions could have a significant impact on projected financial results. This section provides an indication of the financial impact of changes in the following assumptions:

- Domestic load growth
- Interest rates
- Foreign exchange rates
- Export prices
- Capital expenditures
- Water flow conditions
- Rate Increases

Table 13-1 below shows the change in retained earnings and incremental even annual rate increases/(decreases) required to achieve the same level of retained earnings in 2022/23 as forecast in IFF13.

Table 13-1: Financial Impacts of Sensitivity Analysis

	2015/16	2019/20	2022/23	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease)
Low Domestic Load Growth	(15)	(64)	(103)	0.11%
+ 1% Interest	(41)	(299)	(891)	0.99%
- 1% Interest	40	286	827	-1.02%
C$/US$ Down 0.10 (C$ Strengthening)	4	23	(79)	0.14%
C$/US$ Up 0.10 (C$ Weakening)	(4)	(23)	77	-0.14%
Low Export Price	(6)	(143)	(426)	0.50%
High Export Price	(5)	119	348	-0.41%
Capital Expenditures + $100M	(14)	(183)	(463)	0.50%
5 Year Drought (starting in 2015/16)	N/A	(1 583)	N/A	1.81%
+ 1% Rate Increase in 2015	29	110	195	-0.22%
- 1% Rate Increase in 2015	(29)	(110)	(197)	0.22%

13.1 Domestic Load Growth Sensitivity

The 2013 Electric Load Forecast is prepared with the expectation that there is a 50% chance that actual Manitoba energy requirements could be higher or lower than forecast.

Historically, domestic load requirements higher than forecast would result in greater adverse financial impacts than lower domestic loads due to the higher value of opportunity export sales compared to domestic revenues. With the weakening of export electricity prices over the last several years, wholesale market export and domestic retail rates have inverted and the resulting revenue impacts are positive to Manitoba Hydro. The risk represented is the low domestic load growth or the 10th percentile where gross firm energy could decrease by 1 928 GW.h by 2032/33 or 492 MW in system peak energy.

13.2 Interest Rates Sensitivity

Interest rates assumed in IFF13 are projected to rise gradually over the first six years of the forecast. The interest rate sensitivity indicates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds.

13.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to be slightly weaker than the US$ with some gains in the short term and returning to $1.03 (C$/US$) for the remainder of the forecast. In the short to medium term of the forecast, net income is relatively neutral to changes in the exchange rate, due to the effective hedge provided by Manitoba Hydro's exposure management program. The exchange rate sensitivity indicates the financial impacts of the C$/US$ exchange rate being 0.10 higher (C$ weakening) or lower (C$ strengthening) than forecast.

13.4 Export Prices Sensitivity

IFF13 reflects the expected electricity export prices derived from several independent price forecasts for the Midwest independent System Operator (MISO) region. Each price forecast consultant has their own electricity price forecast models, assumptions and view of the future. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These factors include:

- Thermal fuel forecasts (coal and natural gas);
- Future load growth forecasts;
- Profile of existing generation (fuel type, efficiency and operating parameters);
- Profile of potential new generation (fuel type, efficiency, capital cost and required rates of return);
- Generation requirements;
- Power market rules; and

- Future regulation/legislation related to SO_2 (sulfur dioxide), NO_X (nitrous oxide), Hg (mercury) and CO_2 (carbon dioxide) emissions, as well as cooling water releases and coal ash handling.

There is uncertainty in each of these factors, and particular uncertainty as to how future legislative requirements may evolve. In addition to the expected case, forecast consultants provide high and low price cases with their views of potential long-term lower and higher variations from expected export prices. The export price sensitivities provided in this analysis reflect these low and high export price cases, coupled with low and high natural gas prices.

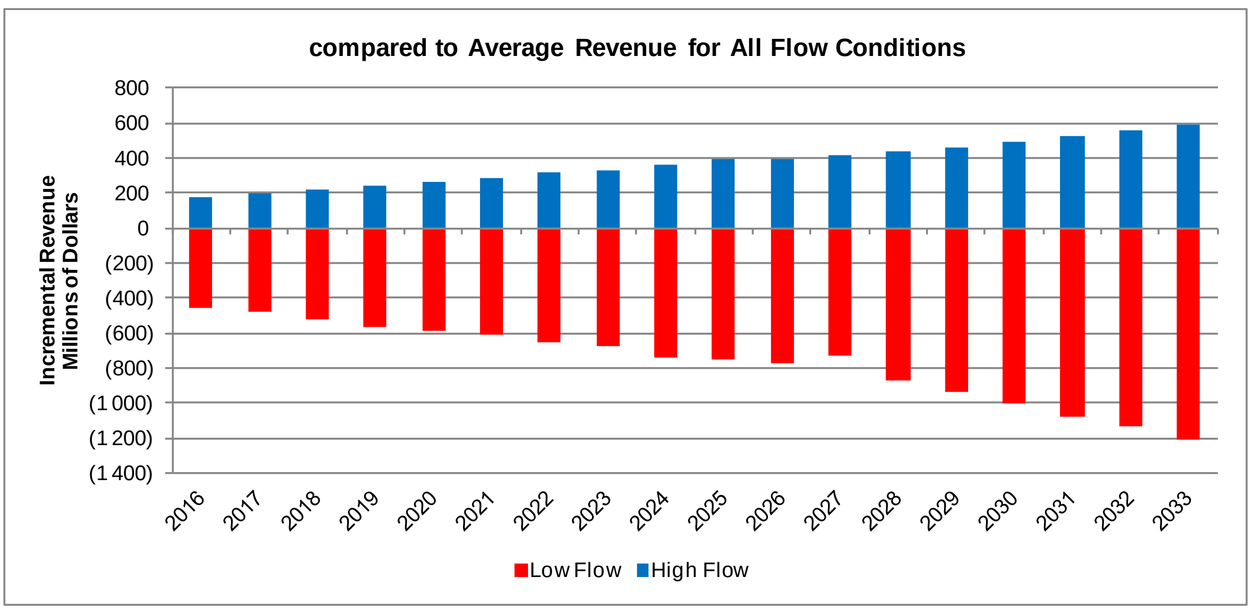
13.5 Capital Expenditures Sensitivity

The capital expenditure sensitivity reflects the financial effects of inflationary increases in excess of general inflation levels and/or additional expenditures necessary to meet reliability, safety, regulatory or customer requirements. In this sensitivity, increases of $100 million per year for electric and $10 million per year for gas have been assumed for non-specified projects.

13.6 Drought/Water Flow Sensitivity

IFF13 reflects the average revenues and expenses of 99 different potential system inflow conditions that occurred historically from 1912/13 to 2010/11. Although the forecast inherently includes the revenues and expenses associated with both the highest and lowest inflow conditions, the actual inflow could vary significantly from forecast in any given year as shown in Figure 13-1. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years.

Figure 13-1: Variability of Net Interchange Revenue



A prolonged period of low flows has a significant financial impact. The current estimate of a recurrence of the historic five-year drought from 1987/88 to 1991/92 is approximately $1.6 billion by the end of the drought period in 2019/20. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2015/16 compared to the average net revenues resulting from all historic flow cases. The costs of drought could rise under a scenario of higher electricity export and thermal fuel prices.

13.7 Rate Increase Sensitivity

Table 13-1 indicates the financial impact of a +/-1% change in the proposed electric rate increase in 2014/15.




Section 2

14.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF13)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers	1 763	1 824	1 914	1 994	2 076	2 168	2 264	2 364	2 471	2 583
BPIII Reserve Account	(18)	(21)	(22)	(23)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
	2 153	2 185	2 253	2 360	2 505	2 616	2 748	3 124	3 333	3 464
Cost of Gas Sold	213	213	227	224	224	224	225	225	226	226
	1 939	1 972	2 026	2 136	2 281	2 392	2 523	2 899	3 108	3 237
Other	29	27	29	30	30	31	32	33	33	34
	1 968	2 000	2 055	2 166	2 311	2 423	2 555	2 931	3 141	3 271
EXPENSES										
Operating and Administrative	556	568	613	620	640	648	660	688	696	712
Finance Expense	472	534	551	607	699	827	881	1 148	1 239	1 240
Depreciation and Amortization	446	474	470	482	520	534	556	634	701	708
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	112	121	130	141	152	155	156	157	159	190
	1 856	1 962	2 049	2 151	2 325	2 488	2 582	3 001	3 187	3 249
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	136	62	24	31	(0)	(55)	(19)	(62)	(45)	20
Additional General Consumers Revenue										
General electricity rate increases	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	0.00%	0.00%	0.50%	0.50%	0.50%	0.50%	0.00%	0.00%	0.50%	0.00%
Financial Ratios										
Equity	24%	22%	18%	16%	15%	14%	13%	12%	11%	11%
Interest Coverage	1.22	1.09	1.03	1.03	1.00	0.95	0.98	0.95	0.97	1.01
Capital Coverage	1.06	0.87	0.80	0.87	1.17	1.07	1.18	1.20	1.35	1.52

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
REVENUES										
General Consumers	2 704	2 830	2 964	3 100	3 246	3 402	3 565	3 736	3 915	4 103
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
	3 586	3 698	3 759	4 077	4 483	4 746	4 907	5 078	5 274	5 463
Cost of Gas Sold	227	227	227	227	228	228	229	229	230	230
	3 359	3 471	3 532	3 849	4 256	4 518	4 678	4 849	5 044	5 233
Other	35	35	36	37	37	38	39	40	40	41
	3 394	3 506	3 568	3 886	4 293	4 556	4 717	4 888	5 084	5 274
EXPENSES										
Operating and Administrative	726	741	756	790	807	824	839	854	872	891
Finance Expense	1 256	1 256	1 251	1 373	1 673	1 851	1 824	1 835	1 776	1 722
Depreciation and Amortization	713	718	728	775	865	922	932	949	958	960
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	200	208	216	223	227	230	230	231	235	234
	3 305	3 350	3 376	3 579	3 990	4 268	4 276	4 320	4 305	4 281
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	82	148	184	297	293	275	425	550	760	970
Additional General Consumers Revenue										
General electricity rate increases	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	1.00%	0.75%	1.00%	0.50%	1.00%	0.75%	0.75%	1.00%	1.00%	1.00%
Financial Ratios										
Equity	11%	11%	11%	11%	12%	13%	14%	16%	18%	22%
Interest Coverage	1.05	1.09	1.10	1.16	1.15	1.14	1.22	1.29	1.42	1.56
Capital Coverage	1.68	1.79	1.86	2.14	2.27	2.32	2.59	2.81	3.18	3.53

CONSOLIDATED PROJECTED BALANCE SHEET (IFF13)
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 904	18 087	19 060	19 887	23 496	24 246	27 774	31 855	32 437	32 950
Accumulated Depreciation	(5 608)	(6 003)	(6 367)	(6 776)	(7 230)	(7 749)	(8 276)	(8 881)	(9 524)	(10 178)
Net Plant in Service	11 296	12 084	12 694	13 111	16 267	16 497	19 498	22 974	22 913	22 772
Construction in Progress	2 427	3 298	4 745	6 456	5 203	6 528	4 783	1 972	3 159	4 984
Current and Other Assets	1 147	1 123	939	1 118	1 572	1 381	1 787	1 956	1 518	1 421
Goodwill and Intangible Assets	262	245	225	209	197	187	175	165	156	150
Regulated Assets	299	290	277	261	244	228	209	194	180	168
	15 432	17 041	18 880	21 155	23 482	24 820	26 453	27 260	27 926	29 495
LIABILITIES AND EQUITY										
Long-Term Debt	10 481	11 921	14 140	16 214	17 443	19 943	21 315	22 248	23 224	24 920
Current and Other Liabilities	1 685	1 762	1 703	1 825	2 860	1 732	2 053	2 035	1 791	1 649
Contributions in Aid of Construction	365	375	384	393	403	418	431	442	453	465
BPIII Reserve Account	18	40	62	85	98	65	33	-	-	-
Retained Earnings	2 678	2 739	2 705	2 736	2 736	2 681	2 662	2 600	2 555	2 575
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 432	17 041	18 880	21 155	23 482	24 820	26 453	27 260	27 926	29 495

CONSOLIDATED PROJECTED BALANCE SHEET (IFF13)
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	33 553	34 244	34 893	41 380	46 094	47 848	48 329	50 225	51 009	51 487
Accumulated Depreciation	(10 840)	(11 509)	(12 183)	(12 905)	(13 717)	(14 588)	(15 469)	(16 368)	(17 275)	(18 185)
Net Plant in Service	22 714	22 735	22 710	28 475	32 377	33 260	32 860	33 857	33 734	33 302
Construction in Progress	6 755	8 242	9 653	5 018	1 717	1 076	1 537	485	396	568
Current and Other Assets	1 786	2 039	2 029	2 229	2 548	2 746	3 086	3 007	3 982	5 195
Goodwill and Intangible Assets	145	140	136	131	127	122	117	113	108	103
Regulated Assets	158	150	142	134	126	120	117	115	114	113
	31 559	33 307	34 670	35 987	36 895	37 325	37 717	37 576	38 334	39 282
LIABILITIES AND EQUITY										
Long-Term Debt	27 114	28 268	29 872	30 874	31 416	31 398	30 871	30 861	30 864	30 677
Current and Other Liabilities	1 425	1 861	1 427	1 436	1 500	1 663	2 148	1 458	1 445	1 605
Contributions in Aid of Construction	477	489	501	513	525	538	550	563	576	590
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 658	2 806	2 990	3 287	3 579	3 854	4 280	4 830	5 589	6 560
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 559	33 307	34 670	35 987	36 895	37 325	37 717	37 576	38 334	39 282

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	2 278	2 312	2 386	2 491	2 627	2 728	2 861	3 239	3 450	3 582
Cash Paid to Suppliers and Employees	(1 185)	(1 207)	(1 294)	(1 325)	(1 365)	(1 385)	(1 403)	(1 474)	(1 502)	(1 556)
Interest Paid	(506)	(523)	(552)	(603)	(710)	(841)	(890)	(1 180)	(1 274)	(1 246)
Interest Received	26	13	16	23	34	37	35	32	29	16
	612	596	556	587	585	539	603	616	703	796
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 346	1 800	2 600	2 400	2 600	2 800	2 000	1 600	1 400	2 000
Sinking Fund Withdrawals	410	103	16	-	13	412	186	270	670	155
Retirement of Long-Term Debt	(610)	(252)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(451)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 030	1 641	2 291	2 053	2 271	1 748	1 870	1 180	1 412	1 698
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 630)	(2 090)	(2 502)	(2 559)	(2 446)	(2 105)	(2 094)	(1 388)	(1 771)	(2 339)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(218)	(225)	(245)	(338)	(245)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 838)	(2 226)	(2 707)	(2 739)	(2 691)	(2 358)	(2 349)	(1 663)	(2 140)	(2 614)
Net Increase (Decrease) in Cash	(196)	11	140	(99)	165	(72)	124	134	(25)	(120)
Cash at Beginning of Year	32	(164)	(153)	(12)	(111)	54	(18)	106	240	214
Cash at End of Year	(164)	(153)	(12)	(111)	54	(18)	106	240	214	94

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 707	3 820	3 884	4 204	4 612	4 878	5 040	5 214	5 412	5 604
Cash Paid to Suppliers and Employees	(1 590)	(1 627)	(1 647)	(1 680)	(1 701)	(1 744)	(1 767)	(1 780)	(1 813)	(1 838)
Interest Paid	(1 243)	(1 259)	(1 259)	(1 397)	(1 720)	(1 917)	(1 901)	(1 935)	(1 852)	(1 819)
Interest Received	17	26	32	42	59	78	87	101	82	102
	890	960	1 009	1 169	1 251	1 295	1 460	1 600	1 829	2 048
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 200	1 600	1 600	1 000	600	200	200	-	-	-
Sinking Fund Withdrawals	29	-	437	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(300)	-	(450)	-	-	(60)	(250)	(700)	(13)	(30)
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 931	1 601	1 587	1 001	601	201	202	3	(16)	(16)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 376)	(2 179)	(2 065)	(1 856)	(1 417)	(1 117)	(945)	(847)	(699)	(654)
Sinking Fund Payment	(265)	(294)	(321)	(326)	(350)	(370)	(384)	(388)	(368)	(382)
Other	(30)	(31)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
	(2 671)	(2 503)	(2 412)	(2 209)	(1 793)	(1 513)	(1 356)	(1 262)	(1 095)	(1 064)
Net Increase (Decrease) in Cash	149	58	184	(39)	58	(17)	306	340	719	968
Cash at Beginning of Year	94	244	302	486	446	505	488	794	1 134	1 853
Cash at End of Year	244	302	486	446	505	488	794	1 134	1 853	2 821

15.0 CAPITAL EXPENDITURE FORECAST (CEF13)

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	14.2	8.0	5.0	21.9	30.2	27.0	16.0	-	-	-	122.3
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	-	-
Slave Falls Major Overhauls	126.1	-	0.2	0.9	5.3	26.6	30.3	31.8	26.9	4.2	-	126.1
Water Licenses & Renewals	56.8	7.6	7.0	7.0	6.5	2.4	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	10.2	10.3	15.3	21.7	19.5	20.4	24.2	19.5	17.1	9.6	167.9
Great Falls Unit 4 Overhaul	53.6	4.6	16.5	11.9	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	6.0	0.4	17.5	7.8	31.7
		36.7	42.1	40.2	55.3	78.6	77.7	78.0	46.7	38.8	17.5	511.6
Transmission												
Rockwood East 230/115kV Station	53.3	13.1	29.1	8.6	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	15.2	30.0	17.2	0.0	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	1.2	3.0	34.9	18.1	1.6	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	1.1	8.9	9.0	9.1	23.7	24.2	24.7	25.1	25.6	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	6.7	7.9	8.9	8.5	5.9	3.4	0.8	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	0.4	16.5	33.2	9.9	3.5	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	2.1	13.3	23.1	57.4	58.5	59.6	213.9
		36.2	71.0	78.4	36.0	35.2	73.6	57.9	85.5	83.6	85.1	642.6
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	2.1	20.0	25.6	16.1	1.3	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	0.1	0.3	3.0	20.0	20.0	7.9	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	0.0	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	51.8
Burrows New 66/12kV Station	54.7	8.7	5.1	-	-	-	-	-	-	-	-	13.8
		10.9	27.9	29.1	39.1	37.8	27.9	9.3	-	-	-	182.1
MAJOR CAPITAL TOTAL		**83.8**	**141.1**	**147.7**	**130.5**	**151.7**	**179.2**	**145.1**	**132.3**	**122.4**	**102.6**	**1 336.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Base Capital												
Electric												
Generation Operations	NA	98.2	94.2	87.7	101.8	63.9	59.6	67.2	70.5	73.2	77.8	794.1
Transmission	NA	104.1	114.9	126.1	112.0	70.3	65.6	73.9	77.5	80.5	85.6	910.6
Customer Service & Distribution	NA	175.4	207.6	211.8	229.2	143.8	134.3	151.2	158.6	164.8	175.2	1 751.9
Customer Care & Energy Conservation	NA	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	33.6
Human Resources & Corporate Services	NA	61.4	75.7	54.8	54.8	34.4	32.1	36.2	37.9	39.4	41.9	468.6
Finance & Regulatory	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
		442.4	495.8	483.7	501.3	316.0	295.2	332.1	348.3	361.8	384.4	3 961.0
Gas												
Customer Service & Distribution	NA	35.7	34.9	49.0	34.9	22.3	21.2	24.4	26.1	27.7	30.0	306.2
Customer Care & Energy Conservation	NA	13.7	13.4	12.3	12.1	10.1	9.3	8.5	8.5	8.4	8.5	104.8
		49.4	48.3	61.3	47.0	32.4	30.6	32.8	34.6	36.1	38.5	411.0
BASE CAPITAL TOTAL		**491.8**	**544.1**	**545.1**	**548.3**	**348.3**	**325.8**	**364.9**	**382.9**	**397.9**	**422.9**	**4 372.0**
CONSOLIDATED CEF13 TOTAL		**1 646.6**	**2 061.7**	**2 482.9**	**2 543.1**	**2 358.1**	**2 061.0**	**1 878.1**	**1 372.0**	**1 755.1**	**2 319.1**	**20 477.9**
ELECTRIC CAPITAL TOTAL		**1 597.2**	**2 013.4**	**2 421.6**	**2 496.1**	**2 325.7**	**2 030.5**	**1 845.3**	**1 337.4**	**1 719.1**	**2 280.6**	**20 066.8**
GAS CAPITAL TOTAL		**49.4**	**48.3**	**61.3**	**47.0**	**32.4**	**30.6**	**32.8**	**34.6**	**36.1**	**38.5**	**411.0**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	122.3
Jenpeg Overhaul Program	115.9	2.7	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	115.9
Slave Falls Major Overhauls	126.1	-	-	-	-	-	-	-	-	-	-	126.1
Water Licenses & Renewals	56.8	-	-	-	-	-	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	7.4	3.3	0.2	0.1	-	-	-	-	-	-	178.9
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	18.8	-	-	-	-	-	-	-	-	-	50.4
		28.8	6.3	21.7	21.8	23.3	1.2	45.4	(3.4)	0.6	-	657.3
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	-	-	-	-	-	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	19.8	-	-	-	-	-	-	-	-	-	233.7
		19.8	-	-	-	-	-	-	-	-	-	662.4
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	-	-	-	-	-	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	13.8
		-	-	-	-	-	-	-	-	-	-	182.1
MAJOR CAPITAL TOTAL		**48.6**	**6.3**	**21.7**	**21.8**	**23.3**	**1.2**	**45.4**	**(3.4)**	**0.6**	**-**	**1 501.8**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Base Capital												
Electric												
Generation Operations	NA	71.7	83.9	81.5	81.1	81.0	83.7	76.5	84.0	84.5	84.6	1 606.6
Transmission	NA	78.8	92.3	89.7	89.3	89.1	92.1	84.2	92.4	93.0	93.1	1 804.4
Customer Service & Distribution	NA	251.7	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	4 506.1
Customer Care & Energy Conservation	NA	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	74.6
Human Resources & Corporate Services	NA	38.6	45.1	43.9	43.7	43.6	45.0	41.2	45.2	45.5	45.5	905.9
Finance & Regulatory	NA	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.8
		444.7	486.9	477.0	481.6	485.2	510.8	474.5	524.8	525.3	530.6	8 902.4
Gas												
Customer Service & Distribution	NA	28.3	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	658.8
Customer Care & Energy Conservation	NA	9.1	9.2	9.3	9.4	9.1	9.2	9.3	9.5	9.6	9.7	198.2
		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0
BASE CAPITAL TOTAL		**482.1**	**529.8**	**519.7**	**525.0**	**529.1**	**556.6**	**518.0**	**572.5**	**574.1**	**580.5**	**9 759.4**
CONSOLIDATED CEF13 TOTAL		**2 359.3**	**2 161.5**	**2 047.5**	**1 838.5**	**1 398.8**	**1 098.1**	**922.3**	**827.7**	**679.9**	**630.1**	**34 441.6**
ELECTRIC CAPITAL TOTAL		**2 321.9**	**2 118.6**	**2 004.7**	**1 795.1**	**1 355.0**	**1 052.3**	**878.8**	**780.0**	**631.0**	**580.2**	**33 584.5**
GAS CAPITAL TOTAL		**37.4**	**42.9**	**42.8**	**43.4**	**43.8**	**45.8**	**43.5**	**47.7**	**48.9**	**49.9**	**857.0**

16.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH13)

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers										
at approved rates	1 396	1 408	1 423	1 438	1 452	1 471	1 490	1 508	1 528	1 548
additional*	0	56	115	177	243	314	390	470	555	646
BPIII Reserve Account	(18)	(21)	(22)	(23)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
Other	13	13	13	14	14	14	14	15	15	15
	1 799	1 838	1 890	1 995	2 138	2 247	2 378	2 753	2 960	3 089
EXPENSES										
Operating and Administrative	485	494	542	548	567	574	586	612	620	633
Finance Expense	437	499	514	567	657	784	838	1 105	1 195	1 195
Depreciation and Amortization	415	440	437	448	485	499	521	600	667	675
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	93	101	109	121	131	134	135	136	138	168
Corporate Allocation	9	9	9	9	9	9	9	9	9	9
	1 707	1 807	1 896	1 992	2 163	2 324	2 417	2 835	3 020	3 081
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	116	55	12	19	(12)	(67)	(31)	(75)	(60)	6
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
General Consumers										
at approved rates	1 568	1 588	1 609	1 629	1 649	1 672	1 694	1 715	1 737	1 758
additional*	742	844	952	1 067	1 188	1 317	1 454	1 599	1 751	1 913
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
Other	16	16	16	16	17	17	17	18	18	19
	3 206	3 315	3 373	3 688	4 091	4 350	4 507	4 674	4 865	5 050
EXPENSES										
Operating and Administrative	646	660	673	705	720	735	748	762	778	794
Finance Expense	1 210	1 210	1 204	1 325	1 623	1 801	1 772	1 784	1 724	1 670
Depreciation and Amortization	679	684	694	741	829	886	895	911	918	921
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	178	185	194	200	204	206	208	208	212	211
Corporate Allocation	9	9	9	9	9	9	9	7	6	6
	3 132	3 175	3 197	3 397	3 803	4 079	4 083	4 123	4 102	4 075
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	68	133	168	281	277	259	408	532	742	952
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	93.20%	100.84%	108.77%

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 237	17 381	18 305	19 095	22 681	23 407	26 910	30 963	31 516	31 998
Accumulated Depreciation	(5 434)	(5 814)	(6 168)	(6 564)	(7 003)	(7 508)	(8 019)	(8 609)	(9 236)	(9 875)
Net Plant in Service	10 803	11 568	12 137	12 531	15 677	15 900	18 891	22 355	22 280	22 124
Construction in Progress	2 425	3 296	4 743	6 454	5 200	6 525	4 779	1 967	3 154	4 978
Current and Other Assets	1 649	1 669	1 534	1 742	2 172	2 055	2 375	2 440	2 057	2 111
Goodwill and Intangible Assets	188	172	154	139	127	118	107	96	87	81
Regulated Assets	220	213	203	190	180	169	159	149	142	134
	15 285	16 918	18 770	21 056	23 357	24 767	26 310	27 007	27 720	29 428
LIABILITIES AND EQUITY										
Long-Term Debt	10 464	11 904	14 123	16 197	17 426	19 926	21 298	22 231	23 207	24 903
Current and Other Liabilities	1 653	1 760	1 726	1 870	2 890	1 848	2 093	1 978	1 795	1 805
Contributions in Aid of Construction	362	372	382	391	401	413	425	437	449	462
BPIII Reserve Account	18	40	62	85	98	65	33	-	-	-
Retained Earnings	2 584	2 638	2 592	2 611	2 599	2 533	2 502	2 427	2 366	2 372
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 285	16 918	18 770	21 056	23 357	24 767	26 310	27 007	27 720	29 428

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	32 572	33 228	33 848	40 307	44 992	46 716	47 170	49 034	49 786	50 231
Accumulated Depreciation	(10 520)	(11 173)	(11 836)	(12 546)	(13 347)	(14 206)	(15 074)	(15 960)	(16 853)	(17 749)
Net Plant in Service	22 052	22 055	22 012	27 760	31 645	32 510	32 095	33 074	32 933	32 482
Construction in Progress	6 748	8 235	9 645	5 009	1 707	1 065	1 525	472	382	553
Current and Other Assets	2 348	2 583	2 493	2 700	3 015	3 250	3 556	3 477	4 454	5 669
Goodwill and Intangible Assets	77	72	68	63	58	54	49	45	40	36
Regulated Assets	129	123	119	112	107	103	100	99	98	98
	31 353	33 069	34 336	35 645	36 533	36 982	37 325	37 166	37 906	38 837
LIABILITIES AND EQUITY										
Long-Term Debt	27 097	28 251	29 854	30 857	31 399	31 381	30 853	30 843	30 847	30 660
Current and Other Liabilities	1 456	1 874	1 360	1 376	1 434	1 632	2 084	1 392	1 378	1 538
Contributions in Aid of Construction	475	488	501	514	527	540	553	567	581	596
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 440	2 572	2 741	3 022	3 299	3 558	3 967	4 499	5 241	6 193
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 353	33 069	34 336	35 645	36 533	36 982	37 325	37 166	37 906	38 837

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 818	1 859	1 913	2 019	2 151	2 247	2 378	2 753	2 960	3 089
Cash Paid to Suppliers and Employees	(809)	(817)	(902)	(932)	(971)	(988)	(1 003)	(1 072)	(1 097)	(1 147)
Interest Paid	(491)	(506)	(534)	(582)	(688)	(819)	(868)	(1 157)	(1 251)	(1 222)
Interest Received	26	13	16	23	34	37	35	32	29	16
	544	549	493	528	525	478	542	555	640	735
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 316	1 740	2 570	2 390	2 590	2 800	2 000	1 590	1 390	1 970
Sinking Fund Withdrawals	410	103	16	-	13	412	186	270	670	155
Retirement of Long-Term Debt	(610)	(217)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(431)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 000	1 616	2 261	2 043	2 261	1 748	1 870	1 170	1 402	1 688
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 578)	(2 039)	(2 439)	(2 511)	(2 413)	(2 074)	(2 061)	(1 352)	(1 735)	(2 300)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(218)	(225)	(245)	(338)	(245)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 786)	(2 175)	(2 644)	(2 691)	(2 658)	(2 326)	(2 315)	(1 627)	(2 103)	(2 574)
Net Increase (Decrease) in Cash	(243)	(10)	111	(120)	128	(101)	97	99	(61)	(151)
Cash at Beginning of Year	25	(218)	(227)	(117)	(237)	(109)	(209)	(112)	(14)	(74)
Cash at End of Year	(218)	(227)	(117)	(237)	(109)	(209)	(112)	(14)	(74)	(225)

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 206	3 315	3 373	3 688	4 091	4 350	4 507	4 674	4 865	5 050
Cash Paid to Suppliers and Employees	(1 177)	(1 211)	(1 227)	(1 256)	(1 273)	(1 311)	(1 331)	(1 341)	(1 369)	(1 390)
Interest Paid	(1 218)	(1 234)	(1 233)	(1 370)	(1 691)	(1 888)	(1 870)	(1 904)	(1 820)	(1 785)
Interest Received	17	26	32	42	59	78	87	101	82	102
	828	897	945	1 105	1 186	1 229	1 393	1 530	1 758	1 976
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 190	1 580	1 590	980	590	180	160	(10)	(20)	(50)
Sinking Fund Withdrawals	29	-	437	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(290)	-	(450)	-	-	(60)	(220)	(700)	(13)	-
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 931	1 581	1 577	981	591	181	192	(7)	(36)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 338)	(2 135)	(2 021)	(1 812)	(1 372)	(1 070)	(901)	(798)	(650)	(603)
Sinking Fund Payment	(265)	(294)	(321)	(326)	(350)	(370)	(384)	(388)	(368)	(382)
Other	(30)	(30)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(2 633)	(2 459)	(2 368)	(2 164)	(1 749)	(1 466)	(1 312)	(1 213)	(1 045)	(1 013)
Net Increase (Decrease) in Cash	125	19	154	(78)	28	(56)	273	310	677	928
Cash at Beginning of Year	(225)	(100)	(81)	73	(6)	23	(33)	240	550	1 228
Cash at End of Year	(100)	(81)	73	(6)	23	(33)	240	550	1 228	2 155

17.0 GAS OPERATIONS FINANCIAL FORECAST (CGM13)

GAS OPERATIONS (CGM13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers										
at approved rates	367	360	374	375	375	376	377	378	380	381
additional revenue requirement*	0	0	2	3	5	7	7	7	9	9
	367	360	376	378	380	383	384	386	389	390
Cost of Gas Sold	213	213	228	224	224	224	225	225	226	226
Gross Margin	153	147	149	154	156	159	159	160	163	164
Other	2	2	2	2	2	2	2	2	2	2
	155	149	150	156	158	160	161	162	164	165
EXPENSES										
Operating and Administrative	67	69	67	68	68	69	70	71	71	73
Finance Expense	16	17	19	21	23	23	24	24	24	25
Depreciation and Amortization	28	31	29	30	31	32	32	31	32	31
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	148	147	152	155	157	158	159	161	163
Net Income	12	1	4	4	3	3	3	3	4	3

* Additional Revenue Requirement	2015	2016	2017	2018	2019	2020	2021	2022	2023
Percent Increase	0.00%	0.50%	0.50%	0.50%	0.50%	0.00%	0.00%	0.50%	0.00%
Cumulative Percent Increase	0.00%	0.50%	1.00%	1.51%	2.02%	2.02%	2.02%	2.53%	2.53%

GAS OPERATIONS (CGM13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ASSETS										
Plant in Service	690	722	764	795	813	830	849	870	893	918
Accumulated Depreciation	(238)	(246)	(248)	(255)	(261)	(269)	(277)	(285)	(294)	(303)
Net Plant in Service	452	476	516	540	552	561	572	585	599	615
Construction in Progress	2	2	2	2	2	3	4	5	5	6
Current and Other Assets	84	84	84	84	84	84	84	84	84	84
Goodwill and Intangible Assets	8	7	5	5	4	4	3	3	3	3
Regulated Assets	79	77	74	70	64	58	50	44	38	34
	625	646	682	702	707	710	715	722	731	743
LIABILITIES AND EQUITY										
Long-Term Debt	290	350	380	390	400	400	400	410	400	420
Current and Other Liabilities	117	77	79	86	77	74	75	70	86	76
Contributions in Aid of Construction	43	43	42	42	43	44	46	45	44	43
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	54	55	59	63	66	70	73	76	80	82
	625	646	682	702	707	710	715	722	731	743

GAS OPERATIONS (CGM13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	403	396	412	410	412	415	417	418	421	423
Cash Paid to Suppliers and Employees	(345)	(358)	(357)	(358)	(359)	(360)	(362)	(364)	(366)	(369)
Interest Paid	(18)	(18)	(20)	(22)	(23)	(24)	(24)	(24)	(25)	(25)
	40	20	35	30	30	31	30	30	30	29
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	60	30	10	10	-	-	10	10	30
Retirement of Long-Term Debt	-	(35)	-	-	-	-	-	-	-	(20)
Other	-	-	-	-	-	-	-	-	-	-
	30	25	30	10	10	-	-	10	10	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(51)	(49)	(62)	(48)	(33)	(31)	(33)	(36)	(37)	(40)
Other	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(0)	(0)	(0)
	(51)	(49)	(62)	(48)	(33)	(32)	(34)	(36)	(37)	(40)
Net Increase (Decrease) in Cash	19	(4)	3	(8)	7	(2)	(4)	4	4	(1)
Cash at Beginning of Year	(26)	(7)	(11)	(8)	(16)	(9)	(11)	(14)	(10)	(7)
Cash at End of Year	(7)	(11)	(8)	(16)	(9)	(11)	(14)	(10)	(7)	(8)

18.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS13)

CORPORATE SUBSIDIARIES (CS13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES										
Revenue	58	57	62	63	64	65	67	68	69	71
Cost of Operations	33	34	37	37	38	39	40	40	41	42
	24	23	25	25	26	27	27	28	28	29
EXPENSES										
Operating and Administrative	14	15	15	15	15	16	16	16	16	16
Finance Expense	(0)	(0)	(0)	-	-	-	-	-	-	-
Depreciation and Amortization	1	2	2	2	2	2	2	1	0	0
Capital and Other Taxes	0	1	1	1	1	1	1	1	1	1
	16	17	17	18	18	18	18	18	17	17
Net Income	8	6	8	8	8	8	9	10	11	12

CORPORATE SUBSIDIARIES (CS13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	13	14	16	16	16	16	16	16	16	16
Accumulated Depreciation	(5)	(6)	(7)	(9)	(10)	(12)	(14)	(14)	(15)	(15)
Net Plant in Service	8	8	8	7	5	4	2	1	1	1
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	43	49	57	66	76	87	98	109	120	132
Goodwill and Intangible Assets	1	1	1	1	0	0	0	0	-	-
Regulated Assets	0	0	0	0	0	0	0	0	0	0
	52	59	66	74	82	91	100	110	121	133
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	11	11	11	11	11	11	11	11	11	11
Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0
Share Captial	1	1	1	1	1	1	1	1	1	1
Retained Earnings	40	46	54	62	70	78	88	98	109	121
	52	59	66	74	82	91	100	110	121	133

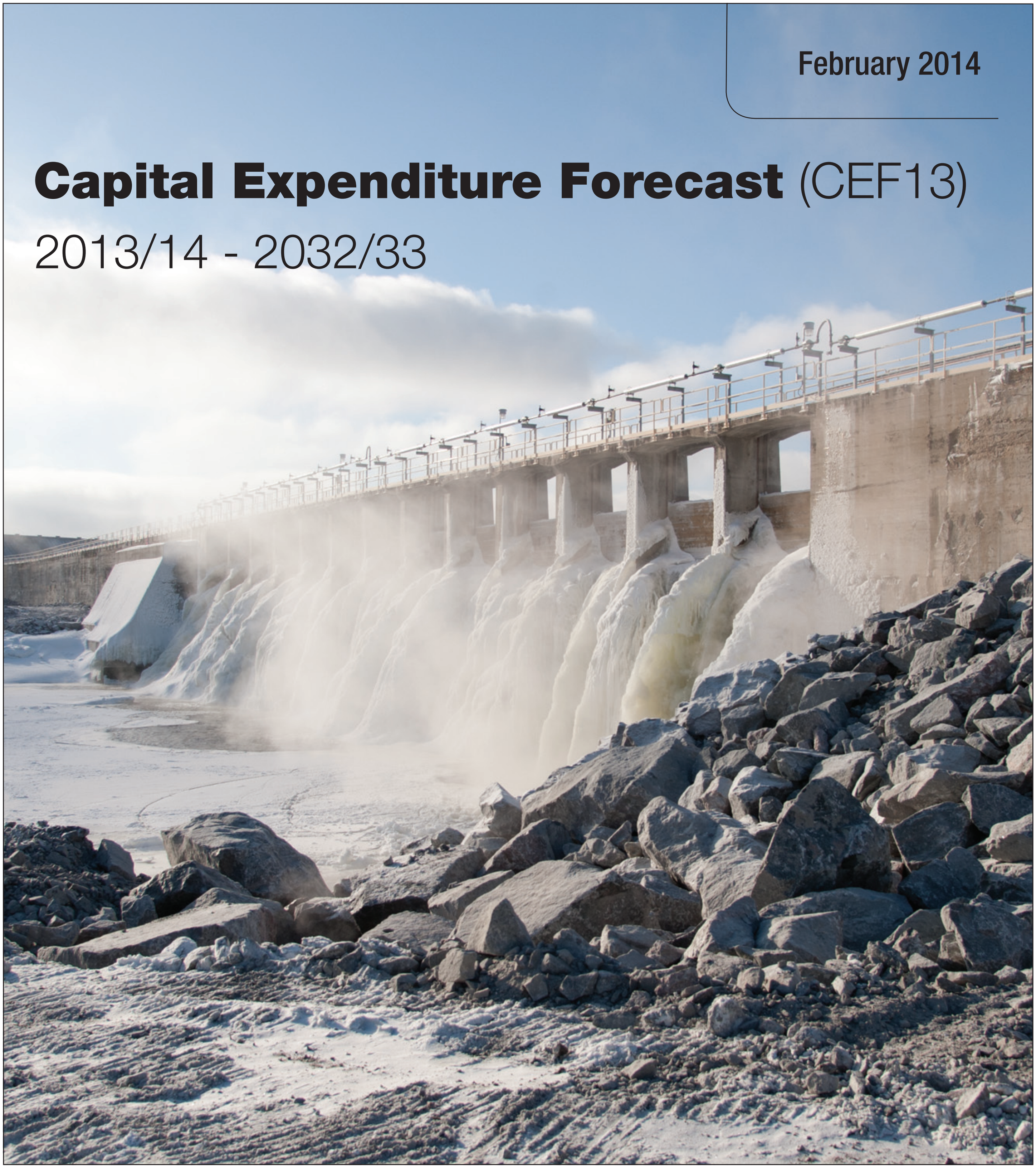
CORPORATE SUBSIDIARIES (CS13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	58	57	62	63	64	65	67	68	69	71
Cash Paid to Suppliers and Employees	(48)	(49)	(52)	(53)	(54)	(55)	(56)	(57)	(58)	(59)
Interest Paid	0	0	0	-	-	-	-	-	-	-
	10	8	9	10	10	10	11	11	11	12
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1)	(2)	(1)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(1)	(2)	(1)	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	8	6	8	10	10	10	11	11	11	12
Cash at Beginning of Year	8	16	22	30	39	49	60	70	81	93
Cash at End of Year	16	22	30	39	49	60	70	81	93	105

February 2014

Capital Expenditure Forecast (CEF13)

2013/14 - 2032/33



Corporate Controller Division
Finance & Regulatory

Manitoba Hydro

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Section 1

Overview

Capital Expenditure Forecast Summary
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1.0 Overview

The Capital Expenditure Forecast (CEF13) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in the Capital Expenditure Forecast will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner.

The Capital Expenditure Forecast is comprised of a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major items are normally greater than $50 million in total cost and the construction period on each major item usually extends beyond one year. Base capital expenditure items typically represent sustaining capital requirements to meet electricity and natural gas service replacements and expansions throughout the province. All major and base capital projects are subjected to a rigorous review and approval process before being included in the Capital Expenditure Forecast. The Capital Expenditure Forecast also includes general provisions, beginning in 2021/22, for expenditures that are necessary to maintain the existing generating station, transmission and distribution systems but for which detailed planning and engineering has not been completed nor received specific project approval.

Base capital targets established for fiscal years 2013/14 through 2016/17 in CEF13 considered increased requirements for aging infrastructure based upon asset condition assessment reports. Beginning in 2017/18, base capital targets are set at $500 million per year and escalated at 1% per year thereafter.

Capital Expenditure Forecast Summary

The CEF13 totals $34 442 million for the twenty year period to 2032/33. Expenditures for Major New Generation & Transmission (MNG&T) total $23 180 million, with the balance of $11 262 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

Comparison to CEF12

The CEF13 for the twenty year period to 2032/33 totals $34 442 million compared to $33 526 million for the same twenty year period included in last year's Capital Expenditure Forecast (CEF12).

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
CEF12	1 895	2 042	2 112	2 258	2 219	1 913	1 718	1 854	2 356	2 323	20 689
Incr (Decr)	(248)	20	371	285	140	148	160	(482)	(601)	(4)	(211)
CEF13	1 647	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	20 478

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
CEF12	2 077	1 883	1 615	1 471	928	1 127	1 047	994	859	834	33 526
Incr (Decr)	282	279	432	367	470	(29)	(125)	(166)	(179)	(204)	916
CEF13	2 359	2 162	2 048	1 838	1 399	1 098	922	828	680	630	34 442

The following table provides a summary of the major changes to CEF13.

	Total Projected Cost	**20 Year Increase (Decrease)**
	($ Millions)	
Electric Demand Side Management*	NA	367
Conawapa - Generation	10 492	324
Transmission Line Upgrades for NERC Alert	151	151
Dorsey - US Border New 500kV Transmission Line	350	146
Electric Base Capital	NA	136
Gas Demand Side Management*	NA	71
Keeyask - Generation	6 220	64
Bipole III - Converter Stations	1 829	63
Riel 230/500kV Station	330	63
Community Development Initiative	61	61
Pointe du Bois Spillway Replacement	560	60
Wuskwatim - Generation	1 449	52
Dawson Road Station - 115/24kV Station	52	52
St. Vital Station - 115/24kV Station	51	51
Gas Base Capital	NA	45
Other Changes	NA	(77)
Sub-total		1 629
CEF12 Overhead Adjustment	NA	(713)
		916

*Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under an interim standard that continues to permit rate regulated accounting.

CAPITAL EXPENDITURE FORECAST (CEF13)

(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	14.2	8.0	5.0	21.9	30.2	27.0	16.0	-	-	-	122.3
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	-	-
Slave Falls Major Overhauls	126.1	-	0.2	0.9	5.3	26.6	30.3	31.8	26.9	4.2	-	126.1
Water Licenses & Renewals	56.8	7.6	7.0	7.0	6.5	2.4	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	10.2	10.3	15.3	21.7	19.5	20.4	24.2	19.5	17.1	9.6	167.9
Great Falls Unit 4 Overhaul	53.6	4.6	16.5	11.9	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	6.0	0.4	17.5	7.8	31.7
		36.7	42.1	40.2	55.3	78.6	77.7	78.0	46.7	38.8	17.5	511.6
Transmission												
Rockwood East 230/115kV Station	53.3	13.1	29.1	8.6	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	15.2	30.0	17.2	0.0	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	1.2	3.0	34.9	18.1	1.6	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	1.1	8.9	9.0	9.1	23.7	24.2	24.7	25.1	25.6	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	6.7	7.9	8.9	8.5	5.9	3.4	0.8	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	0.4	16.5	33.2	9.9	3.5	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	2.1	13.3	23.1	57.4	58.5	59.6	213.9
		36.2	71.0	78.4	36.0	35.2	73.6	57.9	85.5	83.6	85.1	642.6
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	2.1	20.0	25.6	16.1	1.3	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	0.1	0.3	3.0	20.0	20.0	7.9	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	0.0	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	51.8
Burrows New 66/12kV Station	54.7	8.7	5.1	-	-	-	-	-	-	-	-	13.8
		10.9	27.9	29.1	39.1	37.8	27.9	9.3	-	-	-	182.1
MAJOR CAPITAL TOTAL		**83.8**	**141.1**	**147.7**	**130.5**	**151.7**	**179.2**	**145.1**	**132.3**	**122.4**	**102.6**	**1 336.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Base Capital												
Electric												
Generation Operations	NA	98.2	94.2	87.7	101.8	63.9	59.6	67.2	70.5	73.2	77.8	794.1
Transmission	NA	104.1	114.9	126.1	112.0	70.3	65.6	73.9	77.5	80.5	85.6	910.6
Customer Service & Distribution	NA	175.4	207.6	211.8	229.2	143.8	134.3	151.2	158.6	164.8	175.2	1 751.9
Customer Care & Energy Conservation	NA	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	33.6
Human Resources & Corporate Services	NA	61.4	75.7	54.8	54.8	34.4	32.1	36.2	37.9	39.4	41.9	468.6
Finance & Regulatory	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
		442.4	495.8	483.7	501.3	316.0	295.2	332.1	348.3	361.8	384.4	3 961.0
Gas												
Customer Service & Distribution	NA	35.7	34.9	49.0	34.9	22.3	21.2	24.4	26.1	27.7	30.0	306.2
Customer Care & Energy Conservation	NA	13.7	13.4	12.3	12.1	10.1	9.3	8.5	8.5	8.4	8.5	104.8
		49.4	48.3	61.3	47.0	32.4	30.6	32.8	34.6	36.1	38.5	411.0
BASE CAPITAL TOTAL		**491.8**	**544.1**	**545.1**	**548.3**	**348.3**	**325.8**	**364.9**	**382.9**	**397.9**	**422.9**	**4 372.0**
CONSOLIDATED CEF13 TOTAL		**1 646.6**	**2 061.7**	**2 482.9**	**2 543.1**	**2 358.1**	**2 061.0**	**1 878.1**	**1 372.0**	**1 755.1**	**2 319.1**	**20 477.9**
ELECTRIC CAPITAL TOTAL		**1 597.2**	**2 013.4**	**2 421.6**	**2 496.1**	**2 325.7**	**2 030.5**	**1 845.3**	**1 337.4**	**1 719.1**	**2 280.6**	**20 066.8**
GAS CAPITAL TOTAL		**49.4**	**48.3**	**61.3**	**47.0**	**32.4**	**30.6**	**32.8**	**34.6**	**36.1**	**38.5**	**411.0**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	122.3
Jenpeg Overhaul Program	115.9	2.7	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	115.9
Slave Falls Major Overhauls	126.1	-	-	-	-	-	-	-	-	-	-	126.1
Water Licenses & Renewals	56.8	-	-	-	-	-	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	7.4	3.3	0.2	0.1	-	-	-	-	-	-	178.9
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	18.8	-	-	-	-	-	-	-	-	-	50.4
		28.8	6.3	21.7	21.8	23.3	1.2	45.4	(3.4)	0.6	-	657.3
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	-	-	-	-	-	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	19.8	-	-	-	-	-	-	-	-	-	233.7
		19.8	-	-	-	-	-	-	-	-	-	662.4
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	-	-	-	-	-	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	13.8
		-	-	-	-	-	-	-	-	-	-	182.1
MAJOR CAPITAL TOTAL		**48.6**	**6.3**	**21.7**	**21.8**	**23.3**	**1.2**	**45.4**	**(3.4)**	**0.6**	**-**	**1 501.8**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Base Capital												
Electric												
Generation Operations	NA	71.7	83.9	81.5	81.1	81.0	83.7	76.5	84.0	84.5	84.6	1 606.6
Transmission	NA	78.8	92.3	89.7	89.3	89.1	92.1	84.2	92.4	93.0	93.1	1 804.4
Customer Service & Distribution	NA	251.7	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	4 506.1
Customer Care & Energy Conservation	NA	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	74.6
Human Resources & Corporate Services	NA	38.6	45.1	43.9	43.7	43.6	45.0	41.2	45.2	45.5	45.5	905.9
Finance & Regulatory	NA	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.8
		444.7	486.9	477.0	481.6	485.2	510.8	474.5	524.8	525.3	530.6	8 902.4
Gas												
Customer Service & Distribution	NA	28.3	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	658.8
Customer Care & Energy Conservation	NA	9.1	9.2	9.3	9.4	9.1	9.2	9.3	9.5	9.6	9.7	198.2
		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0
BASE CAPITAL TOTAL		**482.1**	**529.8**	**519.7**	**525.0**	**529.1**	**556.6**	**518.0**	**572.5**	**574.1**	**580.5**	**9 759.4**
CONSOLIDATED CEF13 TOTAL		**2 359.3**	**2 161.5**	**2 047.5**	**1 838.5**	**1 398.8**	**1 098.1**	**922.3**	**827.7**	**679.9**	**630.1**	**34 441.6**
ELECTRIC CAPITAL TOTAL		**2 321.9**	**2 118.6**	**2 004.7**	**1 795.1**	**1 355.0**	**1 052.3**	**878.8**	**780.0**	**631.0**	**580.2**	**33 584.5**
GAS CAPITAL TOTAL		**37.4**	**42.9**	**42.8**	**43.4**	**43.8**	**45.8**	**43.5**	**47.7**	**48.9**	**49.9**	**857.0**




Section 2

Project Summaries

ELECTRIC OPERATIONS:

MAJOR NEW GENERATION & TRANSMISSION:

Wuskwatim - Generation

Description:
Design and build the new Wuskwatim generating station with three generators and installed capacity of approximately 200MW on the Burntwood River upstream of Thompson.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power June 2012.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 448.6	$ 12.3	$ 16.2	$ -	$ -	$ -	$ -
Increase (Decrease)	-	32.6	7.6	12.1	-	-	-
Revised Forecast	$ 1 448.6	$ 44.8	$ 23.8	$ 12.1	$ -	$ -	$ -

Wuskwatim - Transmission

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities necessary to integrate the Wuskwatim generating station into the Manitoba Hydro 230kV transmission network as follows: *Transmission*: 230kV lines from Wuskwatim switching station to Thompson Birchtree station, from Wuskwatim switching station to Herblet Lake station, and from Wuskwatim generating station to Wuskwatim switching station. *Terminations*: New 230kV stations at Thompson Birchtree and Wuskwatim, new 230kV 150MVA static var compensator at Thompson Birchtree station, terminate lines into Herblet Lake and replace protection at Kelsey and Thompson Mystery Lake Road stations. *Communications*: system additions for protection of the new transmission lines and stations, including optical power ground wire on the Wuskwatim to Birchtree transmission line.

Justification:
The existing 230kV transmission system in northern Manitoba does not have sufficient capacity to accommodate the additional output of the Wuskwatim generating station. This project will increase the ability of the transmission system to carry the full output of Wuskwatim to load anywhere in Manitoba.

In-Service Date:
First Power June 2012.

Revision:
Cost flow revision and decrease in costs to completion.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 322.9	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(3.1)	2.3	-	-	-	-	-
Revised Forecast	$ 319.8	$ 2.3	$ -	$ -	$ -	$ -	$ -

Herblet Lake - The Pas 230kV Transmission

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Flin Flon Cliff Lake and The Pas Ralls Island as follows: *Transmission*: 230kV line 160km from Herblet Lake to The Pas Ralls Island. *Terminations*: Extend 230kV facilities at Herblet Lake and The Pas Ralls Island stations. *Communications*: Upgrade and co-ordinate with existing Herblet Lake and The Pas facilities.

Justification:
The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads. In addition, this line facilitates the transmission of power from the Wuskwatim generating station.

In-Service Date:
July 2011.

Revision:
Cost flow revision and decrease in costs to completion.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 76.6	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(0.2)	0.3	-	-	-	-	-
Revised Forecast	$ 76.4	$ 0.3	$ -	$ -	$ -	$ -	$ -

Keeyask - Generation

Description:
Design and build the Keeyask generating station with seven generators and nominal capacity of 695MW on the Nelson River downstream of the Kelsey generating station. Project costs also include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. These costs are comprised of extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power November 2019.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 6 220.1	$ 339.0	$ 405.1	$ 636.5	$ 883.9	$ 1 132.1	$ 2 119.6
Increase (Decrease)	-	11.0	65.9	2.8	(18.8)	(20.7)	23.8
Revised Forecast	$ 6 220.1	$ 350.1	$ 471.0	$ 639.3	$ 865.1	$ 1 111.4	$ 2 143.4

Conawapa - Generation

Description:
Design and build the Conawapa generating station with ten generators and nominal capacity of 1 485MW on the Nelson River downstream of the Limestone generating station. Project costs also include activities associated with extensive First Nations and other community consultations, pre-project training, environmental studies, impact statement preparations, submissions, regulatory review processes, acquiring all necessary licensing, improvements to access roadways, and detailed pre-engineering required to obtain a license and all necessary approvals to construct the Conawapa generating station.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power May 2026.

Revision:
In-service deferred one year from May 2025. Increased costs for additional work supporting environmental assessment and EIS submission and 1% PST increase.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$10 192.4	$ 72.0	$ 66.3	$ 118.9	$ 245.3	$ 305.1	$ 9 098.9
Increase (Decrease)	299.1	(2.3)	3.8	7.0	(146.0)	(64.5)	526.2
Revised Forecast	$10 491.5	$ 69.8	$ 70.1	$ 125.9	$ 99.4	$ 240.6	$ 9 625.1

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all seven Kelsey generating station units including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform extensive intake gate rehabilitation, perform draft tube modifications, perform an 8 000 hour inspection, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey generating station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77MW of additional Kelsey output.

In-Service Date:
August 2014.

Revision:
Cost flow revision and in-service advanced three months from November 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 301.7	$ 8.9	$ 9.5	$ -	$ -	$ -	$ -
Increase (Decrease)	-	7.1	(7.3)	-	-	-	-
Revised Forecast	$ 301.7	$ 16.0	$ 2.2	$ -	$ -	$ -	$ -

Kettle Improvements & Upgrades

Description:
Rewind stator for units 5-12 and install a new stator frame, core and winding for units 1-4. Perform rotor refurbishment, excitation upgrade replacements, control and protection system replacements, mechanical systems replacements, and intake gate and wicket gate work for units 1-4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Re-wedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Unit 4 requires repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core.

In-Service Date:
March 2026.

Revision:
Cost flow revision and in-service date deferred three years and five months from October 2022.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 165.7	$ 4.0	$ 19.4	$ 16.0	$ 19.8	$ 16.4	$ 39.5
Increase (Decrease)	-	(0.8)	(11.7)	7.8	(2.6)	(15.3)	21.7
Revised Forecast	$ 165.7	$ 3.2	$ 7.7	$ 23.7	$ 17.3	$ 1.0	$ 61.2

Pointe du Bois Spillway Replacement

Description:
Design and build a new spillway and new concrete and earth fill dams to replace the existing spillway structures. Includes engineering and environmental studies, community consultation, obtaining regulatory approval, and de-commissioning the existing spillway.

Justification:
Pointe du Bois does not currently meet dam safety guidelines with respect to spillway capacity. A new spillway is required to meet these guidelines.

In-Service Date:
March 2014.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 559.6	$ 248.5	$ 81.0	$ 2.3	$ -	$ -	$ -
Increase (Decrease)	-	12.0	44.3	3.2	-	-	-
Revised Forecast	$ 559.6	$ 260.5	$ 125.3	$ 5.5	$ -	$ -	$ -

Pointe du Bois - Transmission

Description:
Redevelop Stafford Terminal station (formerly Scotland station), replace Bank 7 at Pointe du Bois switchyard station, salvage 66kV P lines between Pointe du Bois and Rover stations, install a 115kV transmission line between Pointe du Bois and Whiteshell stations, add Bank 8 to Pointe du Bois switchyard, install a 66kV line between Ridgeway and Rover stations, and upgrade protection at Slave Falls switchyard station.

Justification:
The 66kV lines P1, P2, P3, and P4 between Pointe du Bois and Rover stations have exceeded their expected serviceable life and pose threats to public and employee safety. The reliability of the transmission system in the Winnipeg Central area has been degraded due to the poor physical condition of these lines. In order to successfully operate the power system and continuously deliver high quality power to our customers and protect the public, the P Lines should be removed. The rebuild of Stafford station is required to address due diligence concerns, including Manitoba Hydro grounding and switching standards and public safety, and to increase Winnipeg Central capacity. This work involves converting the 138kV system to 115kV, so work at Pointe du Bois is also required.

In-Service Date:
December 2017.

Revision:
Increase the project budget as a result of two factors: a change in concept for replacement of the four 66kV lines from Pointe du Bois to Rover Stations and higher estimated costs for the Stafford Station Rebuild and Pointe du Bois Bank 7 Replacement. In-service date deferred three years and seven months from May 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 85.9	$ 14.2	$ 20.0	$ -	$ -	$ -	$ -
Increase (Decrease)	28.4	(1.5)	(11.4)	12.3	21.9	7.4	-
Revised Forecast	$ 114.3	$ 12.7	$ 8.6	$ 12.3	$ 21.9	$ 7.4	$ -

Gillam Redevelopment and Expansion Program (GREP)

Description:
Redevelop and expand the Town of Gillam infrastructure in Phases 1B, 2 and 3. Phases 2 & 3 will require further definition based on conceptual design and the requirement of Manitoba Hydro's construction of new facilities in the North.

Justification:
Redevelopment of the Town of Gillam is required to address existing operational needs and to prepare for the growth associated with new generation facilities. The GREP will improve the overall quality of infrastructure in Gillam, which will positively affect attraction and retention for existing and new generation facilities. The GREP supports Corporate initiatives to develop the hydroelectric potential of the Lower Nelson River.

In-Service Date:
March 2027.

Revision:
None.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 366.5	$ -	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 249.2
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 366.5	$ -	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 249.2

Bipole III - Transmission Line

Description:
Design and build a +/- 500kV HVDC transmission line of approximately 1 341km (west of Lakes Winnipegosis & Manitoba) from Riel Converter Station to Keewatinoow Converter Station. Conduct environmental impact assessment, acquire property, and obtain licensing necessary for a +/- 500kV DC transmission line and converter stations at Riel and Keewatinoow.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power, due to decreased line losses (approximately 76MW under full existing generation).

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 259.9	$ 251.3	$ 325.4	$ 320.5	$ 176.2	$ 77.9	$ -
Increase (Decrease)	-	(185.2)	(59.5)	61.5	87.5	117.2	-
Revised Forecast	$ 1 259.9	$ 66.2	$ 265.9	$ 381.9	$ 263.7	$ 195.2	$ -

Bipole III - Converter Stations

Description:
Design and build an HVDC converter station with a rating of 2 000MW at the proposed Keewatinoow site, including property acquisition costs and the Keewatinoow 230kV AC switch yard. Design and build an HVDC converter station with 2 000MW of converters at Riel, including three synchronous compensators, property acquisition costs and the Riel 230kV AC switch yard.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 828.5	$ 231.1	$ 408.9	$ 379.2	$ 394.3	$ 177.3	$ -
Increase (Decrease)	-	(52.1)	(146.3)	114.0	16.0	4.3	127.4
Revised Forecast	$ 1 828.5	$ 179.0	$ 262.6	$ 493.2	$ 410.2	$ 181.5	$ 127.4

Bipole III - Collector Lines

Description:
Design and construct three permanent and two temporary 230kV collector lines for the Keewatinoow Converter Station. Construct power substation for the Keewatinoow Converter Station. Design and construct the Riel and Keewatinoow electrode lines, sectionalize the 230kV transmission line R49R at Riel. Includes the property acquisition and/or easements for the collector lines and the electrode lines.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 191.4	$ 84.0	$ 43.6	$ 30.0	$ 11.1	$ 2.0	$ -
Increase (Decrease)	-	(55.2)	19.8	16.2	26.6	6.5	-
Revised Forecast	$ 191.4	$ 28.8	$ 63.5	$ 46.2	$ 37.7	$ 8.5	$ -

Community Development Initiative

Description:
Establishment of an obligation for a Community Development Initiative to provide benefits to First Nations, Community Councils, rural Municipalities and incorporated Towns and Villages within the vicinity of the Bipole III Project.

Justification:
Manitoba Hydro is responding to community feedback seeking longer term benefits for communities in proximity to high voltage transmission facilities. These funds will be available for community development projects that benefit a broad segment of eligible communities.

In-Service Date:
October 2017.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	60.8	53.9	2.2	2.0	1.8	0.9	-
Revised Forecast	$ 60.8	$ 53.9	$ 2.2	$ 2.0	$ 1.8	$ 0.9	$ -

Riel 230/500kV Station

Description:
Conduct environmental impact assessment and obtain licensing necessary for the Riel 230/500kV station. Design and construct a 230/500kV station at the Riel site including the installation of a 230kV bus with a maximum of five Bays, the installation of a 500kV ring bus, the installation of a 230/500kV 1200MVA transformer bank using two 230kV and one 500kV breaker, and the installation of 500kV line reactors with relocating of a reactor phase from Dorsey. Install a second reactor phase from Dorsey as a spare at Riel after the Riel reactors are in-service and salvage the third reactor phase at Dorsey. Sectionalize two 230kV transmission lines R32V and R33V into Riel station using eight 230kV breakers and associated equipment resulting in two Riel-Ridgeway and two Riel-St. Vital transmission lines. Sectionalize 500kV transmission line D602F into Riel station using two 500kV breakers and associated equipment resulting in Dorsey-Riel and Riel-Forbes 500kV circuits.

Justification:
The sectionalization of the 500kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.

In-Service Date:
October 2014.

Revision:
Increased the project budget following a detailed review of the project scope and estimate including incorporation of award values of all the major contracts. The in-service date is delayed by five months from May 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 267.6	$ 47.3	$ 3.5	$ 2.0	$ -	$ -	$ -
Increase (Decrease)	62.4	26.8	37.3	(1.3)	-	-	-
Revised Forecast	$ 329.9	$ 74.1	$ 40.8	$ 0.7	$ -	$ -	$ -

Firm Import Upgrades

Description:
Reconductor and resag transmission lines SC25, WT34, and SM26, and replace risers and/or current transformers for stations at Whiteshell, Ridgeway, Transcona, and Parkdale.

Justification:
This project will increase to 100MW Manitoba Hydro's firm import capability from Ontario. Increasing the transmission capability will permit greater volume of energy imports during periods when additional energy may be required.

In-Service Date:
August 2015.

Revision:
Cost flow revision and in-service date deferred one year from August 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 19.9	$ 11.7	$ 8.2	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(11.7)	2.6	8.9	-	-	-
Revised Forecast	$ 19.9	$ -	$ 10.8	$ 8.9	$ -	$ -	$ -

Dorsey - US Border New 500kV Transmission Line

Description:
Design, construct and commission a 235km 500kV AC single-circuit transmission line from Dorsey Station to the US border. Design and install one 500kV breaker, one 150MVAr 500kV shunt reactor, one double-wye ungrounded 46kV 73.4MVAr shunt capacitor bank and associated communications and protection at Dorsey. Design and install two 500kV breakers, one 230kV breaker, two double-wye ungrounded 46kV 73.4MVAr shunt capacitor banks, a 1 200MVA 230/500kV autotransformer and associated communications and protection at Riel. Acquire property for right-of-way, conduct environmental impact assessment, conduct community consultations, obtain licensing and perform environmental monitoring for all new facilities. Design, procure and install a new 300MVA phase shifter at Glenboro Station and re-align the transmission lines at the Glenboro Station to accommodate the new transformer.

Justification:
Power sale term sheets have been negotiated with Minnesota Power (250MW) and Wisconsin Public Service (300MW). The existing tie line capacity is insufficient to accommodate the additional sales and therefore a new export line is needed. The proposed transmission facilities will increase the Manitoba to U.S. transfer capability for both export and import purposes.

In-Service Date:
October 2019.

Revision:
Costs were increased for additional line length to run through South Loop to Riel Station before heading south to the US border. Scope was increased to include a phase shifting transformer at Glenboro Station and the required transmission line re-alignment. In-service date advanced seven months from May 2020.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 204.8	$ 0.4	$ 2.0	$ 3.7	$ 25.2	$ 61.8	$ 110.5
Increase (Decrease)	145.6	0.1	1.8	26.0	75.9	(3.1)	44.8
Revised Forecast	$ 350.3	$ 0.4	$ 3.8	$ 29.7	$ 101.1	$ 58.7	$ 155.3

St. Joseph Wind Transmission

Description:
Establish a 230kV generation interconnection from Manitoba Hydro's Letellier station to the St. Joseph Wind Farm Inc.'s 138MW wind farm near St. Joseph, Manitoba. Include the upgrade of 230kV Line L20D (Letellier Station to Drayton Station in North Dakota) and the upgrade of 230kV Line G37C.

Justification:
Manitoba Hydro and St. Joseph Windfarm Inc. signed an Interconnection & Operating Agreement (IOA) on March 18, 2010, for connection of 138MW of generation from the St. Joseph Wind Farm. The IOA requires that Manitoba Hydro install or upgrade facilities in order to provide 138MW of interconnection service.

In-Service Date:
May 2012.

Revision:
Decrease in costs.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 11.2	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(1.2)	-	-	-	-	-	-
Revised Forecast	$ 10.0	$ -	$ -	$ -	$ -	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce electricity consumption in Manitoba.

Justification:
The electric Demand Side Management plan is cost effective as a resource option and is included in Manitoba Hydro's Power Resource Plan (PRP). The DSM plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under an interim standard that continues to permit rate-regulated accounting.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 28.0	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)		-	25.3	24.6	23.9	22.6	270.6
Revised Forecast	NA	$ 28.1	$ 25.3	$ 24.6	$ 23.9	$ 22.6	$ 270.6

MAJOR CAPITAL:

GENERATION OPERATIONS:

Pine Falls Units 1-4 Major Overhauls

Description:
Rehabilitation, replacement of and addition to various equipment such as generator re-wind, stator radial keys, breakers, cooling raditors, instrument transformers, unit control & monitoring systems, excitation system upgrades, governor upgrades, meter upgrades, and powerhouse crane refurbishment. Replace unit 1-4 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials. Conduct a model test and up-rate study.

Justification:
Assessment of the mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
April 2019.

Revision:
Cost flow revision and in-service date advanced five months from September 2019.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 142.2	$ 6.8	$ 9.2	$ 27.8	$ 27.5	$ 24.5	$ 26.2
Increase (Decrease)	-	7.4	(1.2)	(22.8)	(5.6)	5.7	16.8
Revised Forecast	$ 142.2	$ 14.2	$ 8.0	$ 5.0	$ 21.9	$ 30.2	$ 43.0

Jenpeg Overhaul Program

Description:
Major overhaul of all six generating units to inspect, repair, modify, and replace components of the turbine/ generator. Areas of concern include journal bearings, thrust bearings, turbine seals, servo motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, and auxiliary systems.

Justification:
A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

In-Service Date:
December 2031.

Revision:
In-service date deferred ten years from December 2021.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 115.9	$ -	$ -	$ 2.3	$ 2.5	$ 18.2	$ 92.9
Increase (Decrease)	-	-	-	(2.3)	(2.5)	(18.2)	23.0
Revised Forecast	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9

Slave Falls Major Overhauls

Description:
Perform major overhaul for all eight units at Slave Falls generating station, including spillway improvements/ replacements, excitation upgrades, the addition of a Unit Control and Monitoring System (UCMS) Framework, access road upgrades, and a new walkway across the spillway.

Justification:
Many safety, reliability, environmental, efficiency, operational & dam safety issues have been identified relating to the Slave Falls infrastructure. Extensive repairs, modifications and/or replacements will be required to ensure the serviceability of the plant and spillway infrastructure. Economics of this work may suggest that a new spillway be constructed to replace existing spill infrastructure. Current operating procedures include ice load reduction activites at the spilling structures to ensure structural stability. A dam safety concern has been identified with respect to the minimal remote spilling capability at Slave Falls.

In-Service Date:
September 2021.

Revision:
In-service date advanced three years and four months from January 2025.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 126.1	$ -	$ 0.1	$ 0.1	$ 0.2	$ 0.5	$ 125.3
Increase (Decrease)	-	-	0.2	0.8	5.1	26.1	(32.1)
Revised Forecast	$ 126.1	$ -	$ 0.2	$ 0.9	$ 5.3	$ 26.6	$ 93.2

Water Licenses & Renewals

Description:
Conduct hydraulic studies, geotechnical assessments, property status and severance line determinations, mapping, license documentation, environmental reviews, and community informational sessions necessary to secure license finalization and/or renewals for the Corporation's hydraulic plants.

Justification:
All hydraulic generating facilities must be authorized under water power licenses and these licenses need to be clearly in force to significantly reduce risk exposure, maintain operating flexibility, maximize export revenues, and contribute to financial strength.

In-Service Date:
December 2017.

Revision:
Project scope has been expanded to include the International Institute of Sustainable Development (IISD) funding which continues with a new four year agreement, Lower Nelson River Sturgeon Stewardship Agreement (LNRSSA) liability core funding, Lower Nelson River Sturgeon Stewardship Agreement First Nations Committee Costs, the construction of spawning shoals for the Lake Sturgeon Stewardship and Enhancement Program (LSSEP) and the Lake Winnipeg Regulation Final Water Power Act License application with the CEC now requires a comprehensive plain language document be created for the process that covers a multitude of topics.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 53.5	$ 8.2	$ 5.6	$ 5.9	$ 6.2	$ 1.6	$ -
Increase (Decrease)	3.3	(0.6)	1.4	1.1	0.2	0.8	-
Revised Forecast	$ 56.8	$ 7.6	$ 7.0	$ 7.0	$ 6.5	$ 2.4	$ -

Pointe du Bois GS Rehabilitation

Description:
Implement safety upgrades for the Pointe du Bois generating station including fire protection, mechanical hazards, electrical hazards, operational hazards, trips and fall hazards, and various other safety upgrades. Additionally, implement turbine and generator, equipment and civil rehabilitation and upgrades.

Justification:
To provide a high level of health and safety upgrades as well as improved reliability and control, along with a reduction in potential environmental impacts from catastrophic events such as fire or flooding. The plan provides the most economical solution to operate the generating station for an additional twenty years.

In-Service Date:
July 2026.

Revision:
Cost flow revision and in-service date deferred two years and three months from April 2024.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 182.9	$ 7.1	$ 9.0	$ 18.8	$ 23.0	$ 21.3	$ 96.2
Increase (Decrease)	-	3.2	1.3	(3.5)	(1.3)	(1.8)	5.7
Revised Forecast	$ 182.9	$ 10.2	$ 10.3	$ 15.3	$ 21.7	$ 19.5	$ 101.9

Great Falls Unit 4 Overhaul

Description:
Major overhaul to generating Unit 4 including generator rewind, turbine re-runnering, new water passage embedded components, one 3-phase unit transformer, and modernization of components.

Justification:
The re-runnering and major overhaul will provide an opportunity to upgrade/modernize the unit while taking advantage of an already planned outage for the intake gates. The re-runnering will add both capacity and efficiency. The existing transformer is in poor condition and water passage components are starting to fail. The overhaul will increase reliability and extend the asset life by 40 to 50 years.

In-Service Date:
August 2015.

Revision:
In-service date deferred one year and eight months from December 2013. Increase in scope includes: refurbish generating station's service bay floor, upgrade line protection, upgrade powerhouse crane and repair damaged draft tube elbow.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 43.2	$ 19.9	$ 0.2	$ -	$ -	$ -	$ -
Increase (Decrease)	10.5	(15.3)	16.3	11.9	-	-	-
Revised Forecast	$ 53.6	$ 4.6	$ 16.5	$ 11.9	$ -	$ -	$ -

Brandon Units 6 & 7 "C" Overhaul Program

Description:
Perform C inspections/overhauls of the Brandon gas turbines Unit 6 & 7 when each of them acquires 24,000 Equivalent Operating Hours (EOH).

Justification:
The reliability of the hot gas path components cannot be predicted after 24,000 EOH. Failure of hot gas path parts could lead to significant collateral damage and an extended forced outage of the units.

In-Service Date:
March 2024.

Revision:
Cost flow revision and in-service date deferred three years and three months from December 2020.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 50.4	$ -	$ -	$ -	$ 5.9	$ 0.4	$ 44.1
Increase (Decrease)	-	-	-	-	(5.9)	(0.4)	6.3
Revised Forecast	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4

TRANSMISSION:

Rockwood East 230/115kV Station

Description:
Design and construct a new 230/115kV Rockwood East Station adjacent to 230kV circuits A3R (Ashern-Rosser) and S65R (Silver-Rosser) including associated equipment, protection, control and communication systems. Sectionalize and extend 230kV and 115kV transmission lines as required and provide communication and protection upgrades.

Justification:
Construction of the Rockwood East Station with three 115kV line terminations would alleviate the overload scenarios for Rosser 230/115kV Banks 2 and 4 and for 115kV circuits CR4 or CR2 between Rosser and Parkdale Stations. It would also increase the 115kV capacity in the Rosser/Parkdale/Selkirk area. The existing Parkdale 115/66kV Station switchyard has very limited opportunity for adding new capacity due to the station's poor condition and limited space.

In-Service Date:
November 2015.

Revision:
Cost flow revision and in-service date deferred two months from September 2015.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 53.3	$ 15.1	$ 27.1	$ 7.9	$ -	$ -	$ -
Increase (Decrease)	-	(2.0)	1.9	0.7	-	-	-
Revised Forecast	$ 53.3	$ 13.1	$ 29.1	$ 8.6	$ -	$ -	$ -

Lake Winnipeg East System Improvements

Description:
Build a new 115/66kV Manigotagan Corner Station complete with two 6OMVA transformers, a new 65km, 115kV transmission line from Pine Falls Station to Manigotagan Corner Station, the associated terminations and communications, and the salvage of approximately 75kms of 66kV Line L77.

Justification:
Pine Falls Station currently operates over firm transformation during winter peak. The absence of firm transformation would cause customer outages in the Lake Winnipeg East area during a Pine Falls transformer outage. The outage would last greater than a week until a spare transformer could be brought in from Winnipeg and connected. A transformer outage would affect more than 1,300 permanent customers and more than 13,000 seasonal (summer) customers. Deferral will place customers at risk of no supply. The new 115/66kV Manigotagan Corner Station and Pine Falls – Manigotagan Corner 115kV Transmission Line will provide firm capacity for area load for the next 20 years, as well as enable the Bloodvein SVC to control effectively the voltage at Bloodvein, Little Grand Rapids, Beren's River and Poplar River for the next 20 years. It also reduces the loading on Pine Falls 115/66kV accommodating load growth in the Victoria Beach, Grand Beach and Bissett areas.

In-Service Date:
November 2015.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 64.6	$ 22.4	$ 23.8	$ 13.0	$ 2.3	$ -	$ -
Increase (Decrease)	-	(7.2)	6.2	4.2	(2.3)	-	-
Revised Forecast	$ 64.6	$ 15.2	$ 30.0	$ 17.2	$ -	$ -	$ -

Letellier - St. Vital 230kV Transmission

Description:
Design and construct a new 230kV line from Letellier Station to St. Vital Station including associated terminations and communications. Includes environmental licensing and monitoring, and property rights acquisition.

Justification:
The supply to Letellier Station must be improved in order to overcome the contingency loading and low voltage problems in the south central area of Manitoba caused by load growth, as well as to maintain export levels on the 230kV Tie Line L20D (Letellier to Drayton) at these increased loads.

In-Service Date:
August 2016.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 59.0	$ 2.2	$ 7.6	$ 30.8	$ 17.9	$ -	$ -
Increase (Decrease)	-	(1.0)	(4.6)	4.1	0.2	1.6	-
Revised Forecast	$ 59.0	$ 1.2	$ 3.0	$ 34.9	$ 18.1	$ 1.6	$ -

Transmission Line Upgrades for NERC Alert

Description:
Establish a new major capital project involving a nine year program to upgrade over 1000 transmission line spans to meet CSA Standards for line clearance. A priority listing of the transmission lines and spans requiring mitigation will be developed based on assessment work considering operational and safety risks specific to each line/span.

Justification:
This program addresses discrepancies between the design ratings and actual field ratings of transmission lines thereby ensuring continued reliability and operation of the electrical system as well as mitigating risks to public safety due to insufficient line clearance.

In-Service Date:
March 2023.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	151.3	-	1.1	8.9	9.0	9.1	123.2
Revised Forecast	$ 151.3	$ -	$ 1.1	$ 8.9	$ 9.0	$ 9.1	$ 123.2

HVDC Dorsey Synchronous Condenser Refurbishment

Description:
Major inspection, re-wedging and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, SC22Y and SC23Y. Replace coolers to restore original thermal performance on SC21Y, and SC23Y. Repair corrosion problems and replace GEM80 PLC on SC7Y, SC8Y and SC9Y. Modify the 600V transfer scheme for SC8Y, SC7Y & SC9Y.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
October 2019.

Revision:
Cost flow revision and in-service date deferred one year and seven months from March 2018.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 73.3	$ 5.8	$ 8.7	$ 11.0	$ 7.6	$ 5.4	$ 4.8
Increase (Decrease)	-	0.9	(0.7)	(2.1)	0.9	0.5	(0.7)
Revised Forecast	$ 73.3	$ 6.7	$ 7.9	$ 8.9	$ 8.5	$ 5.9	$ 4.2

Dorsey 230kV Phase II Zone Building

Description:
Construction and equipping of two new zone buildings and refurbishing of the existing relay building and equipment. This project also includes installing and replacing various pieces of equipment and modifications to the switchyard.

Justification:
Construction of two new hardened relay buildings plus the hardening and conversion of the existing relay building is the most cost effective and practical option. This approach segregates the 230kV switchyard into three sections, providing for the majority of the 230kV switchyard to remain operational following the loss of a zone building. This meets Manitoba Hydro's system restoration criteria.

In-Service Date:
March 2021.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 63.4	$ -	$ -	$ -	$ 0.4	$ 16.5	$ 46.5
Increase (Decrease)	-	-	-	-	-	(0.1)	0.1
Revised Forecast	$ 63.4	$ -	$ -	$ -	$ 0.4	$ 16.5	$ 46.6

Bipole 2 Thyristor Valve Replacement

Description:
Removal of the existing eight (8) thyristor valve groups and their controls, and replace them with eight new de-ionized water cooled HVDC thyristor valve groups and controls.

Justification:
The Bipole 2 thyristor valves and controls are nearing the end of their useful life and require replacement. Replacing the existing thyristor valve groups and controls with new ones will result in reducing the probability of forced outages. This will result in a significant decrease in failures, reduce maintenance requirements, and generally improved reliability for Bipole 2.

In-Service Date:
October 2023

Revision:
None.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 233.7	$ -	$ -	$ -	$ -	$ 2.1	$ 231.6
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 233.7	$ -	$ -	$ -	$ -	$ 2.1	$ 231.6

CUSTOMER SERVICE & DISTRIBUTION:

New Madison Station - 115/24kV Station

Description:
Build a new 115/24kV St. James Station, new and upgraded feeders, and conversion of St. James, Ness, Berry and King Edward station feeders from 4kV to 24kV.

Justification:
This project is required to ensure firm supply and a reliable system in the St. James area.

In-Service Date:
March 2016.

Revision:
In-service date advanced seven months from October 2016. Project name changed from St. James New Station & 24kV Conversion to New Madison Station – 115/24kV Station. Increase project scope from two to three 115/24kV, 60MVA transformer banks at the new station site. Remove 24kV/4kV feeder conversions from the project scope and re-supply St. James 4kV distribution through 24kV/4kV step-down transformation. Remove new 24kV feeder installations, J54 and J56.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 65.9	$ 18.4	$ 20.8	$ 22.3	$ 0.4	$ -	$ -
Increase (Decrease)	3.7	(16.4)	(0.8)	3.3	15.7	1.3	-
Revised Forecast	$ 69.6	$ 2.1	$ 20.0	$ 25.6	$ 16.1	$ 1.3	$ -

St. Vital Station - 115/24kV Station

Description:
Install a 3-bank 115/24kV station complete with nine feeder positions and protection to replace the existing 24kV distribution at St. Vital Station.

Justification:
The project addresses the equipment rating concerns currently mitigated by station operating restrictions and customer-driven demand for electricity in the area, as well as restoring reliable station contingency plans.

In-Service Date:
December 2018.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	51.3	0.1	0.3	3.0	20.0	20.0	7.9
Revised Forecast	$ 51.3	$ 0.1	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9

Dawson Road Station - 115/24kV Station

Description:
Install a 2-bank 115kV/24kV station complete with six feeder positions and two capacitor banks to replace existing 24kV distribution equipment at Dawson Road Station.

Justification:
Justification is based on fulfilling customer-driven demand for electricity in the area as well as providing a reliable supply to customers in contingency situations.

In-Service Date:
December 2019.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	51.8	-	2.5	0.5	3.0	16.5	29.3
Revised Forecast	$ 51.8	$ -	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 29.3

Burrows New 66/12kV Station

Description:
Build a new two bank 66kV/12kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations.

Justification:
Most of the equipment in this part of Winnipeg has been in service for 77 years. Alfred Station (which supplies Charles Station) lacks access to a satisfactory alternate supply in the event of a 12kV interruption out of Rover Station. Remedial action was recommended for both stations in the Due Diligence Report. It indicated the 4kV switchgear lineups at Alfred and Charles Stations lack arc-resistance and at Alfred Station are sometimes underrated for the available fault current during normal operating conditions. It also had concerns that neither station has an appropriate battery room, all station transformers have patched leaks, they contain asbestos materials, and that spare parts are in short supply.

In-Service Date:
March 2015.

Revision:
In-service date deferred two years from March 2013. Increase estimate to complete the feeder conversions, to install the new 66kV underground supply and other cost revisions.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 42.6	$ 4.2	$ 2.2	$ -	$ -	$ -	$ -
Increase (Decrease)	12.1	4.5	3.0	-	-	-	-
Revised Forecast	$ 54.7	$ 8.7	$ 5.1	$ -	$ -	$ -	$ -

BASE CAPITAL:

ELECTRIC OPERATIONS:

Generation Operations

Description:
These projects are required to provide safe, reliable, efficient supply of power, and to replace plant facilities which are at the end of their useful life. This is comprised of:

GENERATION – Projects relating to upgrading or replacing infrastructure, controls, transformers, breakers, and other equipment at existing generating stations.

GENERATION TOWN SITE SERVICES - Projects required to maintain facilities and provide services to town sites such as Gillam, Grand Rapids and Seven Sisters.

OTHER CAPITAL - Projects relating to upgrading replacing or enhancing domestic water and waste water systems, security systems, office, plant and field equipment replacements; communications; tools and test equipment as well as geotechnical investigation of various contaminated corporate facilities to remediate contaminated areas to environmentally acceptable limits.

Justification:
The generation availability of the older assets has been declining over the last ten years. As Generation Operation's assets age, there is an increase in risk to their availability, which could result in months or years of unit outages and significantly impact the ability to produce power to the transmission system. Enhancements or rehabilitation to the power supply facilities will ensure a safe, reliable and efficient source of energy.

Revision:
Plan reduced to account for the corporate reorganization and transfer of the HVDC Division from Generation Operations to the Transmission Business Unit as well as adjustments to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 102.5	$ 145.7	$ 114.6	$ 92.7	$ 52.5	$ 1 494.9
Increase (Decrease)		(4.3)	(51.4)	(26.9)	9.1	11.4	(334.2)
Revised Forecast	NA	$ 98.2	$ 94.2	$ 87.7	$ 101.8	$ 63.9	$ 1 160.7

Transmission

Description:
The majority of projects consist of additions, improvements and replacement of transmission lines; replacement, development and upgrades to HVDC facilities; replacement, development and upgrades to communication systems; additions and replacement of field maintenance equipment; and station upgrades. This is comprised of:

SYSTEM RELIABILITY – Projects that address the reliability or capacity of the transmission, or communication systems, including system emergencies and regulatory compliance.

HVDC FACILITIES - Projects relating to upgrading or replacing transformers, breakers, smoothing reactors, protection, controls and other equipment at HVDC facilities.

CUSTOMER SERVICE - Projects that address new or existing service extensions to larger customers.

ENVIRONMENTAL - Projects that enhance or restore the environment, mitigate damage or potential damage to the environment or remove/salvage plant.

SAFETY – Projects that address risk to public or employee safety or emergency preparedness.

OTHER- Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
This program ensures the reliability of transmission with respect to load, outages, and import/export requirements; as well as addresses safety issues and provides the necessary support for the operation of the HVDC, transmission and communication systems.

Revision:
Plan increased to account for the corporate reorganization and transfer of the HVDC Division from Generation Operations to the Transmission Business Unit in the early forecast period offset by adjustments to the base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 66.8	$ 90.5	$ 72.3	$ 47.3	$ 39.1	$ 1 657.8
Increase (Decrease)		37.3	24.4	53.8	64.7	31.2	(380.7)
Revised Forecast	NA	$ 104.1	$ 114.9	$ 126.1	$ 112.0	$ 70.3	$ 1 277.0

Customer Service & Distribution

Description:
These projects are required to extend sub-transmission, distribution, and transformation facilities to supply service to residential, farm, commercial and industrial customers, and to replace plant facilities whose useful life has been exceeded. Specific types of expenditures include station and line additions, modifications and rebuilds, bank additions, breaker replacements, defective cable replacement, highway changes, field maintenance equipment, woodpole replacements and ice melting requirements. These costs are spread over many facility locations throughout the Province and are comprised of:

SYSTEM IMPROVEMENTS - Projects relating to additions and modifications to the existing electric distribution network to maintain system reliability and standards of safety, as a result of customer load growth, aging infrastructure and operational standards of performance. Assets and facilities include distribution stations, poles, conductors, transformers, streetlights, cables, duct lines and manholes.

CUSTOMER SERVICE - Projects relating to new or existing service extensions to commercial and residential customers.

NEW STATIONS - Projects relating to station development requirements in both Winnipeg and rural Manitoba to address capacity limitations.

OTHER CAPITAL - Projects relating to VHF radio replacements and field maintenance equipment.

Justification:
The residential, farm, commercial and industrial loads are expected to grow at an average rate in excess of 1.5% per annum and will require a program of additions to the system to accommodate these anticipated loads. As the distribution assets are approaching the end of their designated lifespan a four year program has been established to replace critical infrastructure.

Revision:
Increased target values to accommodate expenditures required to rehabilitate and replace the aging assets based upon condition assessment data.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 176.3	$ 162.8	$ 152.8	$ 142.4	$ 144.7	$ 3 438.3
Increase (Decrease)		(0.9)	44.8	58.9	86.8	(0.8)	100.0
Revised Forecast	NA	$ 175.4	$ 207.6	$ 211.8	$ 229.2	$ 143.8	$ 3 538.3

Customer Care & Energy Conservation

Description:
This program covers the additions and replacements of meters, transformers and related equipment and is comprised of:

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

OTHER– Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Decreases due to the removal of the Advanced Metering Infrastructure program until a review has been completed.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 3.1	$ 7.9	$ 9.3	$ 9.4	$ 9.7	$ 80.1
Increase (Decrease)		-	(4.7)	(6.1)	(6.2)	(6.4)	(21.4)
Revised Forecast	NA	$ 3.1	$ 3.1	$ 3.2	$ 3.3	$ 3.3	$ 58.6

Human Resources & Corporate Services

Description:
The program consists of information technology hardware and software upgrades and application development, corporate building refurbishments and new building programs, fleet vehicle refurbishment and replacement as well as projects associated with property easements, and acquisition of equipment for the training centre, print shop, fleet, materials management, and facilities.

CORPORATE BUILDINGS - Projects associated with the cyclical acquisition, and/or replacement of corporate administrative facilities throughout the Province.

FLEET ACQUISITIONS - Projects associated with the cyclical procurement, refurbishment and/or replacement of corporate fleet vehicles and equipment.

INFORMATION TECHNOLOGY HARDWARE / SOFTWARE - Projects associated with the purchase and installation of hardware and software upgrades, personal computers, networks and cabling.

INFORMATION APPLICATION DEVELOPMENT - Projects associated with developing computer applications. Significant projects include: Enterprise Asset Management, Capital Portfolio Management, Corporate Laboratory Information Management System upgrade, Generation Performance & Reporting System, Predictive Analytics Project and Travel and Expense Management System.

OTHER – Projects associated primarily with property easements and equipment for the training centre, print shop, fleet, materials management and facilities.

Justification:
To provide safe, efficient and productive; corporate buildings, fleet vehicles and equipment. Also to enhance computer systems throughout the corporation to achieve ongoing improvement in productivity and reliability.

Revision:
Increases due mainly to the new fleet building and two new district offices in the earlier forecast years. The decrease in the latter portion is due to the adjustment to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 48.1	$ 53.3	$ 50.6	$ 50.5	$ 51.4	$ 885.5
Increase (Decrease)		13.3	22.4	4.2	4.3	(17.0)	(260.7)
Revised Forecast	NA	$ 61.4	$ 75.7	$ 54.8	$ 54.8	$ 34.4	$ 624.8

Finance & Regulatory

Description:
This program is primarily for meter purchases (for load research monitoring), and handheld devices associated with the load research function. Other items include the purchase of additional servers and other information technology related equipment and specialized software.

Justification:
The load research program supports the development of customer rates and also supports Power Smart initiatives in terms of planning and support.

Revision:
No changes.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8
Increase (Decrease)		-	-	-	-	-	(0.1)
Revised Forecast	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.7

GAS OPERATIONS:

Customer Service & Distribution

Description:
This program consists of projects required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines. This is comprised of:

SYSTEM IMPROVEMENTS – Projects relating to system modifications and betterment. Significant work includes capacity upgrades, system integrity upgrades, regulator station upgrades and cathodic protection upgrades.

NEW BUSINESS - Projects for installing new services and distribution mains for both commercial and residential customers.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

Revision:
Increased costs for infrastructure additions and target increases for unplanned system improvements. The decrease in the latter portion is due to the adjustment to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 22.5	$ 26.7	$ 27.3	$ 27.8	$ 28.4	$ 500.3
Increase (Decrease)		13.2	8.2	21.8	7.1	(6.1)	(18.3)
Revised Forecast	NA	$ 35.7	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 482.0

Customer Care & Energy Conservation

Description:
This program consists primarily of costs to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba, as well as meters, transformers and related equipment. This is comprised of:

GAS DEMAND SIDE MANAGEMENT – Projects to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba.

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service. Also required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Increases due to the assumption that upon adoption of IFRS in 2015/16, the Gas Demand Side Management programs will continue to be capitalized, under an interim standard that continues to permit rate-regulated accounting. These increases are partially offset by the removal of the Advanced Metering Infrastructure program until a review has been completed.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 13.7	$ 6.0	$ 10.6	$ 13.5	$ 5.3	$ 94.1
Increase (Decrease)		-	7.4	1.7	(1.4)	4.8	42.5
Revised Forecast	NA	$ 13.7	$ 13.4	$ 12.3	$ 12.1	$ 10.1	$ 136.6

Section:	Tab 3	**Page No.:**	5
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Comparison with Previous IFF		

PREAMBLE TO IR (IF ANY):

Throughout IFF14 there are comparisons to IFF13

QUESTION:

Does the integrated financial forecast for Electric Operations include the revenues and expenses associated with Manitoba Hydro's subsidiaries? If so, please indicate what the values are for each year for MH13 and MH14.

RATIONALE FOR QUESTION:

IFF14 and CEF14 are compared to the previous year's forecasts. Also, clarify the treatment of subsidiary revenues and costs in the various electric operations forecasts. This goes to the credibility of forecasts.

RESPONSE:

The Electric Operations statements (MH14 and MH13) do not include the revenues and expenses associated with Manitoba Hydro's subsidiaries. The Corporate subsidiaries' projected revenues and expenses are separate and can be found beginning on page 45 in IFF14 (Appendix 3.3).

Section:	Tab 3: Appendix 3.3	Page No.:	(ii) & (iii)
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Executive Summary		
Issue:	Management of Future Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

With reference to page ii (last paragraph) and CEF14 (page 10), please provide a schedule setting out those specific activities related to Conawapa that have not been suspended and contribute to the spending shown for 2014/15 through 2016/17. In each case, please explain why continued spending is required.

RATIONALE FOR QUESTION:

The information request seeks to explore the continued need for spending on Conawapa and Manitoba Hydro's continued efforts towards managing future costs. It poses distinct questions from those in PUB/MH 1-17.

RESPONSE:

Please see the response to MIPUG/MH-I-10a which discusses the purpose for the Conawapa Generation expenditures for 2014/15 through 2016/17. Please see the response to PUB/MH-I-23c for the cost breakdown.

Section:	Tab 3: Appendix 3.3	**Page No.:**	(ii) & (iii)
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Executive Summary		
Issue:	Management of Future Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page (iii), please outline the "further cost containment initiatives" that Manitoba Hydro is pursuing. In doing so, please indicate the time period over which they are expect to apply and what, if any, additional savings (beyond those already incorporated in IFF14) are anticipated.

RATIONALE FOR QUESTION:

The information request seeks to explore the continued need for spending on Conawapa and Manitoba Hydro's continued efforts towards managing future costs. It poses distinct questions from those in PUB/MH 1-17.

RESPONSE:

Manitoba Hydro has identified a number of initiatives that are intended to result in both operating and capital cost savings in order to maintain the proposed 3.95% rate increases.

The following cost savings initiatives are described in Section 5.14 of Tab 5:

- Reduction of Operational Positions
- Consolidation of Rural District Offices
- Managing Contractor Costs in Various Projects
- Review of the Gillam Redevelopment and Expansion Project (GREP)
- Pointe du Bois Operations Spillway Cost Efficiencies

- Implementation of Mobile Workforce Management
- Asset Management Strategies
- Technology Modernization Initiative for Better Capital Investment Decisions
- Supply Change Management Initiatives
- Records Centre Transition to Iron Mountain
- Outage Management System

These initiatives support the Corporation's commitment to limit OM&A expenditures to below inflationary levels of 1% as forecast in IFF14.

In addition to the initiatives outlined above, Manitoba Hydro is continually pursing other strategies that support cost containment. The commitment to cost containment is reinforced in the Corporate Strategic Plan (Appendix 2.1) which identifies one of Manitoba Hydro's operating principles: "Drive continuous improvement by identifying opportunities to streamline processes and improving efficiencies across the organization as a whole."

Section:	Tab 3: Appendix 3.3	Page No.:	(ii) & (iii)
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Executive Summary		
Issue:	Management of Future Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page (iii), please outline what additional capital projects (currently included in CEF14) Manitoba Hydro is considering cancelling or deferring over the next 10 years.

RATIONALE FOR QUESTION:

The information request seeks to explore the continued need for spending on Conawapa and Manitoba Hydro's continued efforts towards managing future costs. It poses distinct questions from those in PUB/MH 1-17.

RESPONSE:

CEF14 is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. The Corporation continually evaluates the priority of its capital expenditures on a regular basis and will advance or defer projects as required, considering financial and operational risks. Please refer to COALITION/MH-I-11a for further information on Manitoba Hydro's prioritization processes.

Section:	Tab 3: Appendix 3.3	**Page No.:**	4-5
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Demand Side Management		
Issue:	Actual and Forecasted DSM Savings and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that shows the actual/forecast annual spending on DSM for the period 2012/13 to 2033/34 based on each of IFF11-2, IFF12, IFF13 and IFF14.

RATIONALE FOR QUESTION:

Understand how the forecast DSM savings and spending have changed from previous IFFs and actual results to-date. This goes to reliability of past forecasts and the reasonableness of the current plan.

RESPONSE:

Please see the response to Coalition/MH I-19g, which shows the actual / forecast annual spending on DSM based on IFF11-2, IFF12, IFF13 and IFF14.

Section:	Tab 3: Appendix 3.3	**Page No.:**	4-5
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Demand Side Management		
Issue:	Actual and Forecasted DSM Savings and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that sets out the annual actual/forecast amortization of DSM costs included in the revenue requirement for the period 2012/13 to 2033/34 based on each of IFF11-2, IFF12, IFF13 and IFF14.

RATIONALE FOR QUESTION:

Understand how the forecast DSM savings and spending have changed from previous IFFs and actual results to-date. This goes to reliability of past forecasts and the reasonableness of the current plan.

RESPONSE:

Please see the following table.

	DSM Amortization ($ Millions)				
	Actual	**IFF14**	**IFF13**	**IFF12**	**IFF11-2**
2012	**26**				26
2013	**28**			28	29
2014	**30**		30	30	-
2015		32	32	-	-
2016		35	32	-	-
2017		38	32	-	-
2018		41	30	-	-
2019		45	27	-	-
2020		51	26	-	-
2021		55	25	-	-
2022		60	24	-	-
2023		63	23	-	-
2024		65	22	-	-
2025		68	21	-	-
2026		67	21	-	-
2027		66	20	-	-
2028		63	19	-	-
2029		60	19	-	-
2030		55	18	-	-
2031		52	18	-	-
2032		50	18	-	-
2033		49	17		
2034		50			

Section:	Tab 3: Appendix 3.3	Page No.:	4-5
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Demand Side Management		
Issue:	Actual and Forecasted DSM Savings and Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that sets on the forecast cumulative energy savings from DSM programs associated with each of the four Integrated Financial Forecasts for each of the years 2012/13 through 2033/34 (excluding the impacts of program spending prior to 2012/13).

RATIONALE FOR QUESTION:

Understand how the forecast DSM savings and spending have changed from previous IFFs and actual results to-date. This goes to reliability of past forecasts and the reasonableness of the current plan.

RESPONSE:

Please see the following table.

		GW.h savings @generation											
Power Smart Plan	**Integrated Financial Forecast**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
2011 Power Smart Plan	IFF11-2	240	412	591	779	969	1,156	1,287	1,411	1,514	1,613	1,687	1,763
2012/13 DSM Base Forecast	IFF-12	0	99	276	439	613	792	941	1,072	1,180	1,278	1,371	1,452
2013-16 Power Smart Plan (15 Year Supplementary Analysis Report)	IFF-13	0	0	174	335	510	694	833	958	1,059	1,153	1,245	1,312
2014-17 Power Smart Plan (15 Year Supplementary Analysis Report)	IFF-14	0	0	0	363	660	1,064	1,445	1,890	2,301	2,641	2,913	3,101

		GW.h savings @generation										
Power Smart Plan	**Integrated Financial Forecast**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
2011 Power Smart Plan	IFF11-2	1,831	1,895	1,944	1,933	1,913	1,890	1,877	1,860	1,855	1,855	1,853
2012/13 DSM Base Forecast	IFF-12	1,488	1,520	1,567	1,624	1,642	1,627	1,610	1,595	1,576	1,524	1,447
2013-16 Power Smart Plan (15 Year Supplementary Analysis Report)	IFF-13	1,357	1,396	1,445	1,505	1,552	1,535	1,518	1,504	1,493	1,451	1,372
2014-17 Power Smart Plan (15 Year Supplementary Analysis Report)	IFF-14	3,284	3,428	3,567	3,699	3,839	3,978	4,051	4,119	4,180	4,243	4,302

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	Page No.:	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide schedules in a similar format to Appendix 11.19 (pages 3-4) based on IFF10, IFF11-2 and IFF12 for the period through to 2032/33 (or as available in each IFF).

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Please see the attached schedules of Average Unit Revenue/Cost for IFF10-2, IFF11-2 and IFF12.

AVERAGE UNIT REVENUE CALCULATION: IFF10-2

VOLUMES (in GW.h)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Demand:										
Manitoba Domestic Energy Sales	21049	21406	21663	22106	22339	22633	22970	23181	23405	23703
Domestic energy Losses	2922	3015	2874	2971	3008	3067	3185	2931	2981	3017
Firm & Opportunity Export Sales to Canada	453	409	754	712	702	674	657	657	647	472
Firm & Opportunity Export Sales to US	10417	8747	7085	6859	6579	6302	6002	5922	5696	6494
Export Transmission Losses	991	844	723	692	662	631	595	586	561	568
Total Demand Volumes:	**35832**	**34421**	**33099**	**33341**	**33290**	**33307**	**33409**	**33277**	**33289**	**34254**
Supply:										
MH Hydraulic Generation	34066	31360	30632	30801	30747	30755	30772	30588	30543	30648
MH Thermal Generation	80	89	413	410	391	379	390	424	437	206
Purchased Energy	1686	2972	2054	2130	2153	2173	2247	2265	2309	3400
Total Supply Volumes:	**35832**	**34421**	**33099**	**33341**	**33290**	**33307**	**33409**	**33277**	**33289**	**34254**
REVENUE/COST (in millions of dollars)										
Manitoba Domestic Energy Sales @ Approved Rates	1 194.396	1 222.667	1 234.645	1 254.182	1 264.873	1 279.182	1 295.669	1 307.088	1 319.996	1 335.987
Additional Domestic Revenue	0.000	41.587	87.200	135.121	185.714	238.808	295.336	353.782	415.640	481.801
Total Manitoba Domestic Energy Sales	1 194.396	1 264.254	1 321.845	1 389.303	1 450.587	1 517.990	1 591.005	1 660.870	1 735.636	1 817.788
Total Export Sales to Canada	15.916	14.805	44.424	44.943	48.720	50.830	51.991	54.890	56.694	45.044
Total Export Sales to USA	338.199	364.037	415.338	424.341	437.392	515.183	523.240	544.371	549.971	710.117
Total Export Sales	354.115	378.842	459.762	469.284	486.112	566.013	575.231	599.261	606.665	755.161
MH Hydraulic Generation	113.871	106.981	102.342	102.906	102.725	102.751	102.809	102.195	102.044	102.396
MH Thermal Generation	5.852	5.070	33.361	36.348	38.601	40.226	43.375	49.625	53.412	30.072
Purchased Energy	49.456	117.291	117.689	126.841	135.429	141.242	150.788	156.391	164.043	238.676
AVERAGE UNIT REVENUE ($/MW.h))										
Manitoba Domestic Energy Sales @ Approved Rates	$ 56.74	$ 57.12	$ 56.99	$ 56.74	$ 56.62	$ 56.52	$ 56.41	$ 56.39	$ 56.40	$ 56.36
Additional Domestic Revenue	-	1.94	4.03	6.11	8.31	10.55	12.86	15.26	17.76	20.33
Total Manitoba Domestic Energy Sales @ meter	56.74	59.06	61.02	62.85	64.93	67.07	69.27	71.65	74.16	76.69
Total Export Sales to Canada	35.13	36.20	58.90	63.11	69.44	75.42	79.11	83.50	87.60	95.49
Total Export Sales to USA	32.47	41.62	58.62	61.87	66.48	81.75	87.18	91.93	96.55	109.35
Total Export Sales	32.58	41.38	58.65	61.99	66.77	81.14	86.38	91.09	95.64	108.41
MH Hydraulic Generation	$ 3.34	$ 3.41	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	73.15	56.97	80.74	88.71	98.82	106.16	111.17	117.14	122.15	145.98
Purchased Energy	29.33	39.47	57.30	59.55	62.90	64.99	67.10	69.03	71.04	70.20

AVERAGE UNIT REVENUE CALCULATION: IFF10-2

VOLUMES (in GW.h)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Demand:										
Manitoba Domestic Energy Sales	23998	24291	24592	24905	25228	25593	25960	26333	26707	27080
Domestic energy Losses	3036	3055	3114	3281	3279	3321	3380	3449	3508	3577
Firm & Opportunity Export Sales to Canada	438	436	432	373	544	736	747	742	723	704
Firm & Opportunity Export Sales to US	7965	9249	9260	10370	12960	13427	13184	12760	12485	12165
Export Transmission Losses	721	859	860	980	1258	1324	1303	1258	1225	1188
Total Demand Volumes:	**36158**	**37890**	**38258**	**39909**	**43269**	**44400**	**44575**	**44542**	**44648**	**44713**
Supply:										
MH Hydraulic Generation	32709	34433	34788	36658	40199	41400	41621	41557	41584	41577
MH Thermal Generation	221	424	446	521	376	327	313	300	313	319
Purchased Energy	3228	3034	3023	2731	2695	2673	2641	2685	2751	2818
Total Supply Volumes:	**36158**	**37890**	**38258**	**39909**	**43269**	**44400**	**44575**	**44542**	**44648**	**44713**
REVENUE/COST (in millions of dollars)										
Manitoba Domestic Energy Sales @ Approved Rates	1 351.599	1 367.068	1 383.049	1 399.844	1 417.223	1 436.615	1 456.218	1 476.109	1 496.123	1 515.866
Additional Domestic Revenue	551.442	596.011	642.459	691.019	741.688	795.350	851.196	909.346	969.777	1 032.291
Total Manitoba Domestic Energy Sales	1 903.041	1 963.079	2 025.508	2 090.863	2 158.911	2 231.965	2 307.414	2 385.455	2 465.900	2 548.157
Total Export Sales to Canada	44.023	42.691	43.675	37.685	58.154	79.491	84.389	88.096	89.162	90.481
Total Export Sales to USA	890.042	1 034.865	1 067.082	1 220.450	1 556.390	1 648.214	1 668.197	1 667.754	1 687.352	1 697.454
Total Export Sales	934.065	1 077.556	1 110.757	1 258.135	1 614.544	1 727.705	1 752.586	1 755.850	1 776.514	1 787.935
MH Hydraulic Generation	109.281	115.039	116.227	122.473	134.303	138.318	139.054	138.843	138.933	138.906
MH Thermal Generation	33.928	69.007	75.018	89.134	64.850	58.376	57.569	56.858	61.073	64.120
Purchased Energy	228.206	225.286	233.631	217.092	223.009	227.034	230.261	240.598	253.901	267.663
AVERAGE UNIT REVENUE ($/MW.h))										
Manitoba Domestic Energy Sales @ Approved Rates	$ 56.32	$ 56.28	$ 56.24	$ 56.21	$ 56.18	$ 56.13	$ 56.09	$ 56.06	$ 56.02	$ 55.98
Additional Domestic Revenue	22.98	24.54	26.12	27.75	29.40	31.08	32.79	34.53	36.31	38.12
Total Manitoba Domestic Energy Sales @ meter	79.30	80.81	82.36	83.95	85.58	87.21	88.88	90.59	92.33	94.10
Total Export Sales to Canada	100.51	97.87	101.08	101.06	106.81	108.06	112.97	118.66	123.37	128.61
Total Export Sales to USA	111.74	111.89	115.24	117.69	120.09	122.75	126.53	130.70	135.15	139.53
Total Export Sales	111.15	111.26	114.61	117.11	119.56	121.99	125.80	130.04	134.50	138.94
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	153.21	162.79	168.06	171.14	172.64	178.57	183.82	189.53	195.12	201.23
Purchased Energy	70.69	74.26	77.28	79.49	82.75	84.92	87.19	89.62	92.31	95.00

AVERAGE PRICE CALCULATION: IFF11-2

VOLUMES (in GW.h)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Demand:										
Manitoba Domestic Energy Sales	21147	21749	22261	22488	22523	22796	23173	23351	23728	24119
Domestic energy Losses	3496	3161	3181	3223	3237	3272	3022	3061	3100	3138
Firm & Opportunity Export Sales to Canada	804	915	589	577	603	595	581	570	537	471
Firm & Opportunity Export Sales to US	9440	6337	6537	6378	6257	6048	5853	5673	5845	7713
Export Transmission Losses	876	625	654	632	624	600	575	554	555	736
Total Demand Volumes:	**35763**	**32787**	**33222**	**33299**	**33244**	**33311**	**33204**	**33209**	**33767**	**36177**
Supply:										
MH Hydraulic Generation	33158	29268	30744	30712	30693	30699	30461	30375	30813	33223
MH Thermal Generation	77	111	311	328	314	332	385	430	295	307
Purchased Energy	2530	3497	2259	2350	2328	2371	2449	2495	2751	2738
Total Supply Volumes:	**35765**	**32876**	**33313**	**33390**	**33335**	**33402**	**33296**	**33300**	**33858**	**36268**

REVENUE/COST (in millions of dollars)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Manitoba Domestic Energy Sales @ Approved Rates	1 186.223	1 290.384	1 293.566	1 306.475	1 313.103	1 329.744	1 349.664	1 361.356	1 381.890	1 402.571
Additional Domestic Revenue	0.000	45.260	105.523	156.033	208.272	264.834	325.447	387.404	455.377	527.459
Total Manitoba Domestic Energy Sales	1 186.223	1 335.644	1 399.089	1 462.508	1 521.375	1 594.578	1 675.111	1 748.760	1 837.267	1 930.030
Total Export Sales to Canada	30.020	33.720	25.704	30.824	37.390	41.398	44.821	47.780	48.654	46.621
Total Export Sales to USA	270.237	221.081	277.149	320.013	386.869	415.481	439.948	458.828	513.945	725.031
Total Export Sales	300.257	254.801	302.852	350.838	424.259	456.879	484.769	506.608	562.599	771.652
MH Hydraulic Generation	110.837	97.834	102.715	102.608	102.546	102.564	101.771	101.482	102.945	110.999
MH Thermal Generation	9.323	9.386	21.929	25.643	25.530	28.061	34.026	40.391	36.076	38.836
Purchased Energy	83.914	120.044	108.483	120.490	125.566	133.687	143.093	151.183	167.962	171.345

AVERAGE PRICE ($/MW.h))	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Manitoba Domestic Energy Sales @ Approved Rates	$ 56.10	$ 59.33	$ 58.11	$ 58.10	$ 58.30	$ 58.33	$ 58.24	$ 58.30	$ 58.24	$ 58.15
Additional Domestic Revenue	0.00	2.08	4.74	6.94	9.25	11.62	14.04	16.59	19.19	21.87
Total Manitoba Domestic Energy Sales @ meter	56.10	61.41	62.85	65.04	67.55	69.95	72.29	74.89	77.43	80.02
Total Export Sales to Canada	37.34	36.85	43.66	53.39	62.03	69.62	77.14	83.81	90.54	98.93
Total Export Sales to USA	28.63	34.89	42.40	50.17	61.83	68.70	75.17	80.88	87.92	94.00
Total Export Sales	29.31	35.14	42.50	50.44	61.85	68.78	75.34	81.14	88.14	94.29
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	121.08	84.56	70.61	78.22	81.42	84.54	88.28	93.91	122.44	126.61
Purchased Energy	33.17	34.33	48.03	51.26	53.93	56.37	58.43	60.59	61.06	62.58

AVERAGE PRICE CALCULATION: IFF11-2

VOLUMES (in GW.h)	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Demand:										
Manitoba Domestic Energy Sales	24468	24814	25161	25510	25865	26266	26648	27026	27392	27760
Domestic energy Losses	3166	3237	3302	3342	3487	3525	3579	3629	3688	3732
Firm & Opportunity Export Sales to Canada	559	555	538	386	553	689	663	651	632	633
Firm & Opportunity Export Sales to US	8396	8264	8188	9296	12179	12978	12692	12343	12048	11885
Export Transmission Losses	819	804	775	887	1194	1279	1242	1202	1167	1149
Total Demand Volumes:	**37409**	**37674**	**37964**	**39420**	**43277**	**44736**	**44823**	**44852**	**44927**	**45160**
Supply:										
MH Hydraulic Generation	34591	34813	34685	36500	40442	41715	41670	41637	41638	41837
MH Thermal Generation	298	305	324	299	251	262	278	275	276	276
Purchased Energy	2612	2647	3045	2712	2675	2850	2965	3031	3104	3139
Total Supply Volumes:	**37500**	**37765**	**38055**	**39511**	**43368**	**44827**	**44914**	**44943**	**45018**	**45251**

REVENUE/COST (in millions of dollars)	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Manitoba Domestic Energy Sales @ Approved Rates	1 421.635	1 440.557	1 459.652	1 478.804	1 498.358	1 520.624	1 541.314	1 561.748	1 581.673	1 601.558
Additional Domestic Revenue	603.097	682.933	767.293	822.484	879.993	941.345	1 004.062	1 068.956	1 135.879	1 205.194
Total Manitoba Domestic Energy Sales	2 024.732	2 123.490	2 226.945	2 301.288	2 378.351	2 461.969	2 545.376	2 630.704	2 717.552	2 806.752
Total Export Sales to Canada	54.997	57.003	57.101	47.325	62.910	76.069	75.887	77.396	77.846	80.783
Total Export Sales to USA	808.434	822.968	837.452	1 023.829	1 290.968	1 394.691	1 411.875	1 404.792	1 408.400	1 424.775
Total Export Sales	863.431	879.971	894.552	1 071.153	1 353.878	1 470.761	1 487.762	1 482.188	1 486.246	1 505.557
MH Hydraulic Generation	115.572	116.313	115.886	121.946	135.118	139.370	139.220	139.108	139.113	139.776
MH Thermal Generation	39.123	41.425	45.594	43.612	38.365	41.181	45.084	45.980	47.736	49.235
Purchased Energy	170.701	179.710	206.998	188.473	190.629	208.679	222.634	233.009	244.857	253.887

AVERAGE PRICE ($/MW.h))	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Manitoba Domestic Energy Sales @ Approved Rates	$ 58.10	$ 58.06	$ 58.01	$ 57.97	$ 57.93	$ 57.89	$ 57.84	$ 57.79	$ 57.74	$ 57.69
Additional Domestic Revenue	24.65	27.52	30.50	32.24	34.02	35.84	37.68	39.55	41.47	43.41
Total Manitoba Domestic Energy Sales @ meter	82.75	85.58	88.51	90.21	91.95	93.73	95.52	97.34	99.21	101.11
Total Export Sales to Canada	98.43	102.66	106.17	122.49	113.84	110.43	114.54	118.87	123.17	127.58
Total Export Sales to USA	96.29	99.59	102.28	110.14	106.00	107.47	111.24	113.81	116.90	119.88
Total Export Sales	96.42	99.78	102.52	110.63	106.34	107.62	111.41	114.06	117.21	120.27
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	131.32	135.82	140.72	145.81	153.02	157.18	161.91	167.37	172.79	178.45
Purchased Energy	65.36	67.89	67.97	69.50	71.28	73.21	75.08	76.87	78.89	80.89

AVERAGE UNIT REVENUE/COST CALCULATION IFF12

VOLUMES (in GW.h)	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Demand:										
Manitoba Domestic Energy Sales	21748	22330	22547	22781	22987	23336	23720	23945	24333	24701
Domestic energy Losses	3400	3267	3197	3225	3225	2935	2991	3000	3033	3078
Firm & Opportunity Export Sales to Canada	756	830	646	633	633	613	605	612	477	493
Firm & Opportunity Export Sales to US	8690	8183	6521	6263	6063	5995	5599	5485	8032	8997
Export Transmission Losses	813	804	640	615	595	582	540	529	744	839
Total Demand Volumes:	**35407**	**35414**	**33551**	**33517**	**33503**	**33461**	**33455**	**33572**	**36620**	**38108**
Supply:										
MH Hydraulic Generation	32904	32232	30838	30823	30808	30659	30621	30872	33405	34827
MH Thermal Generation	85	84	320	337	332	369	364	228	211	226
Purchased Energy	2418	3098	2393	2357	2363	2433	2471	2472	3004	3055
Total Supply Volumes:	**35407**	**35414**	**33551**	**33517**	**33503**	**33461**	**33456**	**33572**	**36620**	**38108**
REVENUE/COST (in milions of dollars)										
Manitoba Domestic Energy Sales @ Approved Rates	1 320.902	1 360.887	1 373.679	1 389.710	1 403.712	1 424.295	1 446.831	1 461.817	1 484.567	1 506.294
Additional Domestic Revenue	0.000	47.631	104.238	164.514	228.182	296.933	370.695	447.070	530.603	619.132
Total Manitoba Domestic Energy Sales	1 320.902	1 408.518	1 477.917	1 554.224	1 631.894	1 721.228	1 817.526	1 908.887	2 015.170	2 125.426
Total Export Sales to Canada	28.318	20.902	22.169	24.667	27.638	29.167	31.446	34.780	28.690	31.558
Total Export Sales to USA (includes net Trans charges)	267.927	273.052	274.218	307.301	322.984	349.015	351.825	370.822	622.306	746.281
Total Export Sales	296.245	293.954	296.387	331.968	350.622	378.182	383.271	405.602	650.996	777.838
MH Hydraulic Generation	109.643	107.741	103.029	102.980	102.930	102.433	102.303	103.142	111.606	116.357
MH Thermal Generation	6.791	5.674	19.029	22.158	23.354	27.736	28.594	22.772	21.916	24.321
Purchased Energy	87.076	111.204	114.321	122.860	129.648	138.848	146.382	152.079	173.296	180.635
AVERAGE UNIT REVENUE/COST ($/MW.h))										
Manitoba Domestic Energy Sales @ Approved Rates	$ 60.74	$ 60.94	$ 60.93	$ 61.00	$ 61.07	$ 61.04	$ 61.00	$ 61.05	$ 61.01	$ 60.98
Additional Domestic Revenue	-	2.13	4.62	7.22	9.93	12.72	15.63	18.67	21.81	25.07
Total Manitoba Domestic Energy Sales @ meter	60.74	63.08	65.55	68.23	70.99	73.76	76.62	79.72	82.82	86.05
Total Export Sales to Canada	38.95	28.32	39.93	45.49	50.98	55.83	61.12	66.67	74.22	78.41
Total Export Sales to USA	30.83	33.37	42.05	49.06	53.27	58.22	62.84	67.61	77.47	82.95
Total Export Sales	31.36	32.61	41.36	48.14	52.36	57.23	61.78	66.52	76.50	81.96
MH Hydraulic Generation	$ 3.33	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	79.89	67.55	59.50	65.70	70.36	75.20	78.63	99.72	103.73	107.75
Purchased Energy	36.01	35.90	47.77	52.12	54.88	57.07	59.23	61.53	57.70	59.12

AVERAGE UNIT REVENUE/COST CALCULATION IFF12

VOLUMES (in GW.h)	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Demand:										
Manitoba Domestic Energy Sales	25078	25462	25854	26233	26605	27003	27415	27825	28232	28638
Domestic energy Losses	3134	3212	3284	3338	3423	3467	3525	3596	3657	3701
Firm & Opportunity Export Sales to Canada	464	474	455	459	670	835	813	797	798	789
Firm & Opportunity Export Sales to US	9014	8450	7991	9162	11836	12217	11913	11564	11351	11086
Export Transmission Losses	836	775	717	859	1157	1205	1169	1129	1106	1075
Total Demand Volumes:	**38526**	**38373**	**38300**	**40051**	**43692**	**44726**	**44835**	**44911**	**45144**	**45290**
Supply:										
MH Hydraulic Generation	35202	34928	34618	36887	40743	41662	41699	41697	41907	41990
MH Thermal Generation	236	233	263	240	214	197	201	201	196	198
Purchased Energy	3088	3212	3419	2924	2734	2868	2935	3013	3041	3102
Total Supply Volumes:	**38526**	**38373**	**38300**	**40051**	**43692**	**44726**	**44835**	**44911**	**45144**	**45290**

REVENUE/COST (in milions of dollars)										
Manitoba Domestic Energy Sales @ Approved Rates	1 528.519	1 551.628	1 575.365	1 598.077	1 620.507	1 644.110	1 668.561	1 692.913	1 716.960	1 741.059
Additional Domestic Revenue	713.461	814.144	921.476	1 034.808	1 154.791	1 282.832	1 419.244	1 563.705	1 716.381	1 877.992
Total Manitoba Domestic Energy Sales	2 241.980	2 365.772	2 496.841	2 632.885	2 775.298	2 926.942	3 087.805	3 256.618	3 433.341	3 619.051
Total Export Sales to Canada	30.160	33.542	33.613	35.964	53.476	68.490	69.683	71.331	74.627	76.505
Total Export Sales to USA (includes net Trans charges)	781.254	766.206	753.706	835.424	1 089.509	1 151.614	1 165.013	1 170.055	1 184.630	1 191.326
Total Export Sales	811.414	799.748	787.319	871.387	1 142.985	1 220.104	1 234.696	1 241.387	1 259.257	1 267.830
MH Hydraulic Generation	117.610	116.694	115.659	123.240	136.123	139.191	139.315	139.308	140.010	140.287
MH Thermal Generation	26.260	26.666	31.012	29.933	27.564	26.062	27.575	28.511	28.720	29.876
Purchased Energy	190.947	204.190	224.140	187.046	184.201	198.915	209.424	220.744	229.030	240.063

AVERAGE UNIT REVENUE/COST ($/MW.h))										
Manitoba Domestic Energy Sales @ Approved Rates	$ 60.95	$ 60.94	$ 60.93	$ 60.92	$ 60.91	$ 60.89	$ 60.86	$ 60.84	$ 60.82	$ 60.79
Additional Domestic Revenue	28.45	31.97	35.64	39.45	43.40	47.51	51.77	56.20	60.80	65.58
Total Manitoba Domestic Energy Sales @ meter	89.40	92.91	96.57	100.37	104.31	108.39	112.63	117.04	121.61	126.37
Total Export Sales to Canada	80.88	87.60	92.20	97.80	92.27	92.07	96.44	100.96	105.51	109.58
Total Export Sales to USA	86.67	90.68	94.32	91.18	92.05	94.26	97.80	101.18	104.36	107.46
Total Export Sales	85.61	89.62	93.22	90.57	91.39	93.48	97.02	100.42	103.65	106.76
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	111.27	114.58	118.08	124.72	128.53	132.60	136.94	141.59	146.26	151.03
Purchased Energy	61.83	63.57	65.55	63.97	67.36	69.35	71.36	73.27	75.32	77.38

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	Page No.:	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm which IFF was the basis for the tables filed with the recent NFAT Application as Appendix 11.3.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

MH12 was the starting point for each of the eight development plans that were evaluated in the NFAT. The development plans differed in the quantum and timing of the capital investment required to meet load requirements and therefore, each plan contains specific export revenue and cost forecasts related to its unique development sequence. In addition, the eight development plans included an updated electricity export price forecast and the inclusion of Great Northern Transmission Line costs compared to MH12.

Although the initial NFAT financial evaluations were based on MH12, subsequent analyses were provided as exhibits/undertakings to the proceedings which analyzed multiple development plans (Plans 1, 5 and 14) under an updated set of assumptions from MH13. Specifically, the DSM evaluations contained updated economic assumptions, the 2013 electricity load forecast, the 2013 natural gas and electricity export price forecasts, and updated capital costs for Keeyask, Conawapa and the GNTL.

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	**Page No.:**	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please comment on the actual level of export prices (i.e. average revenue/kWh) for 2011/12, 2012/13 and 2013/14 relative to those forecast in IFF10, IFF11-2, IFF12 and IFF13, providing reasons for any material variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

In accordance with Order 33/15, the following commentary and comparisons are based on IFF11-2 and subsequent forecasts.

There is inherent uncertainty in any long-term forecasting process due to a wide variety of factors including not only market fundamentals (demand/supply/substitution) but also geopolitical and macro-economic factors. Due to the inherent uncertainty Manitoba Hydro utilizes a consensus forecast that aggregates perspectives from at least five of North America's leading energy analyst firms in producing the composite forecast to ensure that a number of expert perspectives are being considered. Long-term forecasts are not intended to predict inter-year volatility/variability within a market caused by short term demand and supply issues including weather related issues. For example the polar vortex weather event in the winter of 2013/14 caused gas and electricity market prices to increase during that winter and materially impacted average annual pricing. However, an individual event, such as a polar vortex event, is not something that can be reliably forecasted.

In retrospect, when looking at the forecast versus actual, IFF11-2 overestimated revenue for the years 2011/12-2013/14, a primary factor driving this diversion is that electricity market price expectations in the underlying forecast were higher. Following the economic downturn of 2008/09 (and resulting commodity price crash), there was a general belief that natural gas and coal prices would rebound quickly as oil prices would and those generation fuel forecasts drive higher prices. However, the price reduction for natural gas was not a short lived event as originally anticipated. Rather the 2008/09 downturn coincided with the rapid increase of shale gas production which meant an abundant supply of natural gas tempered its price growth over the last number of years. Events such as the economic downturn at in 2008/09 and technological change with respect to shale gas are the types of changes were not predicted by forecasters.

In addition, expected long-term electricity prices have been affected by US Government policy with respect to greenhouse gas emissions. US environmental policy has not advanced to the degree expected since the American Clean Energy and Security Act was passed by the House of Representatives in June 2009 but failed to pass the US Senate.

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	Page No.:	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that explains the variance between the annual export revenue values shown in IFF10 and those in IFF14 broken down as between volume, price (US$), exchange rate and other differences for the years 2014/15 and beyond. Please explain any material variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Please see the attached schedule of net extraprovincial price and volume variance between IFF14 and IFF13, IFF12, IFF11-2, and IFF10-2.

Forecasted net extraprovincial revenues in IFF14 are approximately $5.8 billion lower compared to IFF10-2 for the period between 2014/15 to 2029/30; $3.4 billion lower compared to IFF11-2 for the period between 2014/15 and 2030/31; $1.0 billion lower compared to IFF12 for the period 2014/15 and 2031/32; and $1.5 billion lower compared to IFF13 for the period 2014/15 and 2032/33.

Net export volumes are lower in IFF14 when compared to each of the IFF10-2, IFF11-2, IFF12 and IFF13 forecasts mainly due to the deferral or suspension of Conawapa and the resulting reduction in forecast export revenues. The lower net export volumes are partially offset by higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast through increased DSM programs.

Lower forecast electricity export prices result in a reduction to net extraprovincial revenues in IFF14 compared to previous forecasts mainly due to lower forecast natural gas prices.

Variances due to changes in US exchanges rates do not have a significant impact on Manitoba Hydro’s net income due to the natural hedge that exists between US dollar revenues and US dollar cash outflows (from US dollar interest and principal payments and US dollar purchases) as established in Manitoba Hydro’s Foreign Currency Exchange Risk Policy.

(Millions of Dollars)

	MH14 compared to MH13				MH14 compared to MH12				MH14 compared to MH11-2				MH14 compared to MH10-2			
	Price	Volume	US Exchange & Other	Total	Price	Volume	US Exchange & Other	Total	Price	Volume	US Exchange & Other	Total	Price	Volume	US Exchange & Other	Total
2015	(4)	11	25	32	(43)	104	37	98	(95)	122	29	56	(174)	111	13	(51)
2016	(58)	107	56	104	(56)	109	50	103	(147)	123	42	18	(234)	120	21	(92)
2017	14	5	38	57	4	23	32	58	(97)	39	21	(38)	(159)	34	2	(123)
2018	(1)	(17)	33	15	1	9	31	40	(118)	43	20	(56)	(167)	26	1	(140)
2019	(11)	13	34	36	(25)	54	32	60	(132)	66	21	(46)	(172)	52	1	(118)
2020	(8)	17	32	40	(38)	83	29	74	(154)	84	17	(52)	(229)	53	(4)	(180)
2021	(22)	36	58	72	(43)	138	28	123	(166)	173	10	17	(254)	184	(24)	(94)
2022	(18)	53	49	83	(46)	133	19	106	(173)	198	(1)	24	(198)	133	(41)	(105)
2023	(26)	58	58	89	(49)	121	29	101	(182)	209	9	36	(202)	127	(32)	(106)
2024	(22)	82	57	117	(60)	175	30	145	(154)	215	10	71	(157)	(42)	(32)	(231)
2025	(18)	107	57	145	(64)	212	30	178	(202)	70	10	(122)	(203)	(361)	(32)	(597)
2026	(16)	114	52	150	(42)	14	28	(1)	(210)	(257)	8	(459)	(321)	(420)	(31)	(772)
2027	(23)	(59)	52	(30)	(31)	(255)	28	(258)	(218)	(334)	8	(544)	(353)	(403)	(31)	(787)
2028	(8)	(356)	50	(315)	(33)	(336)	27	(341)	(211)	(363)	8	(566)	(360)	(413)	(31)	(804)
2029	(12)	(443)	49	(406)	(54)	(326)	27	(353)	(217)	(349)	8	(558)	(377)	(409)	(30)	(816)
2030	(11)	(436)	48	(398)	(59)	(319)	27	(351)	(210)	(350)	8	(553)	(377)	(407)	(30)	(815)
2031	(13)	(450)	41	(421)	(65)	(338)	22	(382)	(208)	(377)	3	(582)				
2032	(12)	(473)	40	(446)	(66)	(353)	21	(398)								
2033	(14)	(483)	38	(459)												
Total	**(284)**	**(2,113)**	**864**	**(1,534)**	**(770)**	**(754)**	**527**	**(997)**	**(2,893)**	**(689)**	**229**	**(3,353)**	**(3,938)**	**(1,614)**	**(279)**	**(5,831)**

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	**Page No.:**	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that explains the variance between the annual export revenue values shown in IFF11-2 and those in IFF14 broken down as between volume, price (US$), exchange rate and other differences for the years 2014/15 and beyond. Please explain any material variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Please see the response to COALITION/MH-I-24d.

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	**Page No.:**	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that explains the variance between the annual export revenue values shown in IFF12 and those in IFF14 broken down as between volume, price (US$), exchange rate and other differences for the years 2014/15 and beyond. Please explain any material variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Please see the response to COALITION/MH-I-24d.

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	**Page No.:**	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that explains the variance between the annual export revenue values shown in IFF13 and those in IFF14 broken down as between volume, price (US$), exchange rate and other differences for the years 2014/15 and beyond. Please explain any material variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Please see the response to COALITION/MH-I-24d.

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	Page No.:	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

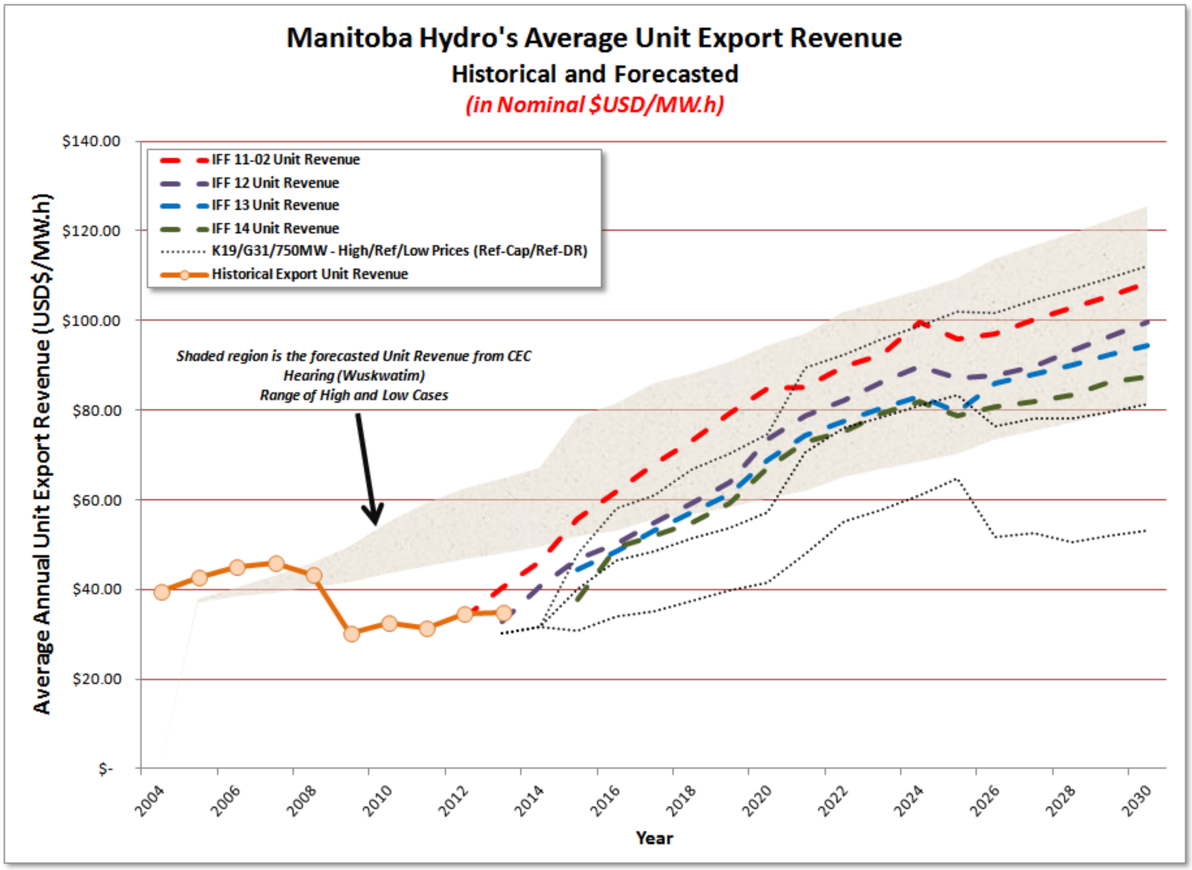
Please provide a graph similar to that in PUB/MH I-19 a) from the last GRA but based on IFF11-2, IFF-12, IFF13 and IFF14. Please show actual values from 2011/12. On the same graph please include the three average export revenue forecasts from the NFATT proceeding based Plan #6 (K19/Gas31/750MW) using the reference outlooks for discount rates and capital costs and the three alternative energy price outlooks. (Note: If there is an alternative Plan from the NFAT that Manitoba Hydro believes more closely approximates the current Power Resource Plan and for which financial statements were prepared, please indicate and substitute for Plan 6).

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

The chart below provides the requested information including average unit export revenue for IFF11-2, IFF12, IFF13, IFF14 and all three pricing cases (High, Reference, Low) for the NFAT case K19/G31/750MW. The chart also includes actual export unit revenue to 2013/14. All prices are expressed in nominal US dollars.


Manitoba Hydro's Average Unit Export Revenue
Historical and Forecasted
(in Nominal $USD/MW.h)
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
IFF 11-02 Unit Revenue
IFF 12 Unit Revenue
IFF 13 Unit Revenue
IFF 14 Unit Revenue
K19/G31/750MW - High/Ref/Low Prices (Ref-Cap/Ref-DR)
Historical Export Unit Revenue
Shaded region is the forecasted Unit Revenue from CEC Hearing (Wuskwatim) Range of High and Low Cases
Average Annual Unit Export Revenue (USD$/MW.h)
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Year

Section:	Tab 3: Appendix 3.3, Figure 5.1 Tab 11: Appendix 11.19	**Page No.:**	7 Pages 3-4
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Extra-Provincial Revenue		
Issue:	Changes in Extra-Provincial Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please comment on the outlook for export prices in IFF14 for the years 2014/15 and beyond relative to the reference export price outlook in the recent NFAT Application and provide the major reasons for the variances.

RATIONALE FOR QUESTION:

The information is required to understand changes as between the extra-provincial revenue forecasts filed in previous PUB proceedings and the actual results/current extra-provincial revenue forecasts in the current Application. It goes to the reliability of export revenue forecasting which is material to rate setting. PUB/MH 1-14, 1-15 pose different questions.

RESPONSE:

Over the 20 year IFF period, the price forecast used for 2014 IFF is approximately 1% lower than the 2012 export price forecast used in the NFAT and approximately 7% lower than the 2013 price forecast used in the NFAT.

The primary drivers for the reduction relative to the 2013 price forecast are lower commodity price forecasts (natural gas and coal) and a reduced market value for capacity.

Section:	Tab 3: Appendix 3.3 Appendix 11.29	Page No.:	11 1
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Operating & Administrative Expense		
Issue:	Adjusted Operating & Administrative Expense		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule of annual actual/forecast Operating and Administrative Expense based on MH14 – starting in 2011/12 and through to 2033/34. For each year after 2011/12, please show the adjustments required to remove: i) the impact of accounting changes and ii) the impact of adding major new facilities (e.g. Wuskwatim, Bipole III, Keeyask and the 500 kV tie line).

RATIONALE FOR QUESTION:

Information is required in order to better understand historical and forecast changes in OM&A expenses which goes to the prudence of expenditures.

RESPONSE:

Please see the following table showing the impact of accounting policy and estimate changes as well as the impact of adding major new facilities. Excluding these changes, annual average increases remain at or below inflationary levels over the 20 year period, demonstrating the Corporation's commitment to contain its operating costs.

Major new facilities are added as the units come online and are added to operations with partial in-service in years 2013 for Wuskwatim, 2019 for Bipole III and 2020 and 2021 for Keeyask. Reductions in 2030 and 2031 are due to the completion of some of the Wuskwatim environmental monitoring commitments.

(in millions of $)

	OM&A - Electric only	Impact of Accounting Chnages	Impact of adding major new facilities	OM&A net of accounting changes & new facilities	OM&A net Yr over Yr %	# of Customers	New Facilities Added
2012	412	(37)	-	375		542,681	
2013	463	(78)	(4)	380	1%	548,774	Wuskwatim (Partial)
2014	481	(91)	(11)	379	0%	555,760	Wuskwatim (Full)
2015	486	(94)	(13)	379	0%	561,825	
2016	542	(146)	(11)	385	1%	568,443	
2017	552	(151)	(11)	389	1%	575,648	
2018	557	(153)	(11)	393	1%	582,805	
2019	571	(154)	(20)	397	1%	589,777	BPIII (Partial)
2020	585	(156)	(28)	402	1%	596,602	BPIII (Full) Keeyask (Partial)
2021	601	(157)	(38)	406	1%	603,152	Keeyask & 500kV TL (Full)
2022	607	(158)	(38)	410	1%	609,374	
2023	619	(161)	(39)	419	2%	615,257	
2024	631	(164)	(40)	428	2%	620,832	
2025	644	(166)	(41)	437	2%	626,211	
2026	657	(169)	(41)	446	2%	631,327	
2027	669	(172)	(42)	456	2%	636,198	
2028	683	(175)	(42)	465	2%	640,842	
2029	697	(178)	(43)	475	2%	645,338	
2030	706	(181)	(40)	485	2%	649,758	Wusk Env. Monitoring
2031	719	(184)	(39)	496	2%	654,128	
2032	733	(185)	(40)	508	2%	658,495	
2033	748	(187)	(41)	520	2%	662,850	
2034	763	(188)	(42)	533	2%	667,223	

Section:	Tab 3: Appendix 3.3 Appendix 11.29	Page No.:	11 1
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Operating & Administrative Expense		
Issue:	Adjusted Operating & Administrative Expense		

PREAMBLE TO IR (IF ANY):

QUESTION:

In the same schedule please add the number of electric customers (actual/forecast) in each year.

RATIONALE FOR QUESTION:

Information is required in order to better understand historical and forecast changes in OM&A expenses which goes to the prudence of expenditures.

RESPONSE:

Please see the response to part COALITION/MH-I-25a.

Section:	Tab 3: Appendix 3.3	Page No.:	12
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Depreciation and Amortization Expense		
Issue:	Change from Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that starting in 2011/12 sets out the Depreciation and Amortization expense for IFF11-2 and IFF14 through to 2031/32. For each IFF, please use actuals were appropriate.

RATIONALE FOR QUESTION:

High level information is required in order to understand change in actual/forecast depreciation and amoritization expense from that filed in the 2012/13 & 2013/14 GRA. More detailed requests are deferred to MIPUG and to PUB/MH 1-38 to 1-46.

RESPONSE:

Please see the following table.

Depreciation and Amortization ($ Millions)

	Actual	IFF14	IFF11-2
2012	353		353
2013	392		401
2014	411		354
2015		405	358
2016		401	375
2017		422	387
2018		445	422
2019		521	468
2020		524	483
2021		613	550
2022		667	576
2023		736	579
2024		752	583
2025		767	615
2026		780	682
2027		791	733
2028		804	741
2029		811	753
2030		820	761
2031		831	793
2032		842	814

Section:	Tab 3: Appendix 3.3	Page No.:	12
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Depreciation and Amortization Expense		
Issue:	Change from Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

For each year, please breakdown the variance between two IFFs into that caused by: i) the difference in assets in service (including regulated assets), ii) the change in depreciation rates as recommended by the recent depreciation study, iii) removal of negative salvage and iv) the change in depreciation methodology.

RATIONALE FOR QUESTION:

High level information is required in order to understand change in actual/forecast depreciation and amoritization expense from that filed in the 2012/13 & 2013/14 GRA. More detailed requests are deferred to MIPUG and to PUB/MH 1-38 to 1-46.

RESPONSE:

Please see the following table for the breakdown of the variance between MH11-2 and MH14.

Depreciation and Amortization

(in millions of dollars)	2012*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MH11-2	**353**	**401**	**354**	**358**	**375**	**387**	**422**	**468**	**483**	**550**	**576**	**579**	**583**	**615**	**682**	**733**	**741**	**753**	**761**	**793**	**814**
Net Assets in Service	(0)	(10)	35	51	58	68	48	90	86	113	138	202	210	187	115	58	65	63	60	33	17
Average Service Life Changes	0	1	(2)	(29)	(34)	(35)	(32)	(39)	(45)	(52)	(43)	(45)	(40)	(36)	(22)	(7)	(11)	(12)	(9)	(6)	0
Removal of Negative Salvage	-	-	55	58	1	1	5	(4)	(11)	(11)	(18)	(16)	(16)	(12)	(3)	3	2	2	2	6	7
Change to IFRS Compliant Depreciation**	-	-	(32)	(33)	1	2	2	6	11	12	14	15	16	13	8	5	6	6	6	4	4
MH14	**353**	**392**	**411**	**405**	**401**	**422**	**445**	**521**	**524**	**613**	**667**	**736**	**752**	**767**	**780**	**791**	**804**	**811**	**820**	**831**	**842**

*Actual values were used in MH11-2 and MH14

**Renamed, it was called "Change in Depreciation Methodology"

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	Page No.:	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the Non-Controlling Interest values shown in the IFF14 Operating statement all relate to the WPLP. If not, please separate of the WPLP values.

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

Confirmed.
The non-controlling interest reflects the portion of NCN's ownership interest in WPLP's net income or losses that is attributed to NCN's capital account on their balance sheet.

KHLP's preferred distributions to the KCN were reclassified from non-controlling interest to a period cost in water rentals in MH14.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	**Page No.:**	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that for 2015/16 and beyond the Non-Controlling Interest values reflect the new agreement with NCN as discussed at Tab 5, page 44.

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

As outlined in Tab 10, Section 10.2.6, the response to PUB Directive 11 from Order 43/13, the parties are still in the process of conducting a review and negotiating final terms. Manitoba Hydro has incorporated projected net impacts to Manitoba Hydro in IFF14 commencing in 2015/16 based on the initial terms as at the time of the preparation of IFF14.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	**Page No.:**	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain more fully the derivation of the Non-Controlling Interest values for the years prior to the new Agreement coming into effect. For example, using 2014/15, how does the projected WPLP loss of $77 M (per Appendix 11.6, page 2) translate into a Non-Controlling Interest value of $25.45 M.

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

The non-controlling interest values are the attribution of NCN's proportionate share of ownership interest in the net income and losses of WPLP to NCN's capital account on their balance sheet. In 2014/15 for example, NCN's 33% share of the net loss of $77.129 million results in a reduction to NCN's capital account of $25.453 million.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	**Page No.:**	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please clarify the impact of the anticipated agreement with NCN. For example, does it: i) change the way the "net income" is calculated for WPLP; ii) change the way the net income (gain or loss) is apportioned to NCN or iii) both?

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

The impact of the anticipated agreement with NCN will change both the way net income or loss is calculated for WPLP and the way net income or loss is attributed to NCN.

As outlined in Tab 10, Section 10.2.6, the response to PUB Directive 11 from Order 43/13, the parties are still in the process of reviewing and negotiating final terms and Manitoba Hydro is not in a position to provide the details of the exact impacts of proposed terms. Once the agreement is finalized and executed, Manitoba Hydro will provide the information as requested.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	Page No.:	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the $15 M impact on Manitoba Hydro referenced at Appendix 3.3, page 13 represents an annual reduction in Manitoba Hydro's net income over the 20-year forecast period. Also, please indicate whether there is any anticipated offsetting gain to Manitoba Hydro in the years following the initial 20-year forecast period.

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

Manitoba Hydro confirms that currently, the $15 million impact represents an annual reduction in the 20-year forecast period. The intent is that there will be offsetting gains in the years beyond the 20-year forecast but the degree to which the gains offset the net impacts in the 20-year forecast period will be dependent upon the actual financial performance of WPLP.

As outlined in Tab 10, Section 10.2.6, the response to PUB Directive 11 from Order 43/13, the parties are still in the process of reviewing and negotiating final terms and Manitoba

Hydro is not in a position to provide details of the exact impacts of proposed terms. Once the agreement is finalized and executed, Manitoba Hydro will provide the information as requested.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	Page No.:	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

What are the assumed annual distributions to KCN that have been included in the Fuel & Power Purchased Expense for IFF14?

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

The response to MIPUG/MH-I-42a explains that the Fuel and Power Purchased expense includes KCN preferred investment adjustments totaling $13.9 million in 2021/22. The preferential distributions projected to be paid to the KCN in IFF14 are included in water rentals.

Section:	Tab 3: Appendix 3.3 Tab 5 Appendix 11.6	**Page No.:**	13 44 2-3 & 8-9
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	First Nation Partnerships		
Issue:	Financial Impacts on Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain how the distributions to KCN were determined based on the forecast operating statement for KHLP provided in Appendix 11.6 (page 8).

RATIONALE FOR QUESTION:

Information is required to better understand the impacts of WPLP and KHLP on Manitoba Hydro. The information goes to the reliability of forecasts and reasonableness of expenditures. The question does not duplicate PUB/MH 1-11.

RESPONSE:

Projected KCN preferred distributions are calculated in accordance with the KHLP Limited Partnership Agreement. For each one per cent of KCN's projected 2.17% total investment[1], preferred distributions are equal to:

- 0.8% of the first two hundred and fifty million ($250,000,000) dollars of Adjusted Gross Revenues earned in Fiscal Years ending after the Final Closing Date, plus

[1] $35.6 million (including KCN's $25 million own cash investment required plus the projected $6.6 million preferential distribution credit described in MIPUG/MH-I-42a) out of $1.45 billion total KHLP equity.

- 1.2% of the amount of Adjusted Gross Revenues in excess of two hundred and fifty million ($250,000,000) dollars and less than or equal to one billion ($1,000,000,000) dollars, plus
- 1.6% of Adjusted Gross Revenues in excess of one billion ($1,000,000,000) dollars.

Adjusted Gross Revenues is a defined term in the KHLP Limited Partnership Agreement which is equal to:

- KHLP revenues, less
- KHLP operating expenses, less
- Amortization and finance expense on Pre-Construction Costs, and less
- Amortization and finance expense on non-major capital costs incurred post Keeyask project in-service.

The KHLP revenues and operating expenses are as shown on the KHLP projected operating statement.

Pre-Construction Costs are defined in the Limited Partnership Agreement as costs incurred after March 31, 2009 up to the construction start (not including the Keeyask Infrastructure Project) along with the associated accrued interest capitalized during construction up to the Keeyask project in-service.

Post Keeyask project in-service capital costs are the annual costs required to upgrade, replace or refurbish components of the Keeyask generating station once it is operational. These costs exclude Major Capital Costs (JKDA) which are capital costs in excess of $40 million.

The following schedule provides the annual calculation for KCN projected preferred distributions to the end of the forecast in 2033/34.

	Adjusted Gross Revenue Calculation (Section 1.01, Pg. 3 LPA)							Post Final Closing Distribution Calculation (Section 6.09(a,i,A) LPA, Pg. 34)						
			Pre- Construction Costs		Non-Major Post-Inservice Capital Costs						1.7%	2.6%	3.5%	
Fiscal Year	KHLP Revenue	KHLP O&M	Amortization	Finance Expense	Amortization	Finance Expense	Adjusted Gross Revenues	1st Tranche	2nd Tranche	3rd Tranche	KCN Preferred Distribution 1st Tranche	KCN Preferred Distribution 2nd Tranche	KCN Preferred Distribution 3rd Tranche	Total KCN Preferred Distribution
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	297.9	14.4	4.0	17.4	-	-	**262.1**	250.0	500.0	1,000.0	4.3	0.3	-	**4.7**
2024	314.6	14.6	4.0	17.1	-	-	**279.0**	250.0	500.0	1,000.0	4.3	0.8	-	**5.1**
2025	324.1	14.8	4.0	16.9	-	-	**288.4**	250.0	500.0	1,000.0	4.3	1.0	-	**5.3**
2026	317.9	14.9	4.0	16.6	-	-	**282.4**	250.0	500.0	1,000.0	4.3	0.8	-	**5.2**
2027	324.2	14.7	4.0	16.4	-	-	**289.2**	250.0	500.0	1,000.0	4.3	1.0	-	**5.4**
2028	331.3	15.0	4.0	16.2	-	-	**296.2**	250.0	500.0	1,000.0	4.3	1.2	-	**5.6**
2029	337.3	15.3	4.0	15.9	-	-	**302.2**	250.0	500.0	1,000.0	4.3	1.4	-	**5.7**
2030	349.0	15.4	4.0	15.7	0.0	-	**314.0**	250.0	500.0	1,000.0	4.3	1.7	-	**6.0**
2031	360.7	14.3	4.0	15.4	0.1	0.2	**326.7**	250.0	500.0	1,000.0	4.3	2.0	-	**6.3**
2032	370.5	14.6	4.0	15.2	0.1	0.2	**336.4**	250.0	500.0	1,000.0	4.3	2.3	-	**6.6**
2033	384.2	14.9	4.0	14.9	0.1	0.2	**350.1**	250.0	500.0	1,000.0	4.3	2.6	-	**7.0**
2034	398.6	15.2	4.0	14.7	0.1	0.2	**364.4**	250.0	500.0	1,000.0	4.3	3.0	-	**7.3**

Section:	Tab 3: Appendix 3.3	**Page No.:**	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

Please provide a schedule that compares the total annual electric capital spending in IFF11-2 with that in IFF14 for the years 2011/12 through 2031/32. Please include actuals for 2011/12 – 2013/14 when setting out the values for IFF14.

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

Please see the following table which compares the capital spending between MH14 and MH11-2 for the years 2012/13 to 2031/32. MH11-2 incorporated actual capital expenditures for 2011/2012 resulting in no variance for that fiscal year and has been excluded from this comparison.

Capital Expenditures (in millions of dollars)	**MH14**	**MH11-2***	**MH14 minus MH11-2**
2013	1 033	1 174	(141)
2014	1 454	1 454	(1)
2015	2 023	1 611	412
2016	2 491	1 931	560
2017	3 073	1 983	1 090
2018	3 125	2 333	792
2019	2 078	1 565	514
2020	1 432	1 808	(377)
2021	999	1 806	(807)
2022	751	1 692	(941)
2023	679	1 502	(823)
2024	681	1 396	(715)
2025	729	1 573	(844)
2026	735	884	(149)
2027	735	739	(4)
2028	730	827	(97)
2029	745	996	(251)
2030	726	942	(217)
2031	770	869	(99)
2032	782	809	(27)

*Includes IFRS OH Adjustment

Section:	Tab 3: Appendix 3.3	**Page No.:**	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

With respect to the response to part (a), please identify those capital projects that account for $10 M or more of the variance between the two forecasts in any given year.

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

Please see the following table which identifies expenditures with variances greater than $10 million between MH14 and MH11-2. MH11-2 incorporated actual capital expenditures for 2011/12 resulting in no variance for that fiscal year and has been excluded from this comparison.

Variance MH14 vs MH11-2

Capital Expenditures (in millions of dollars)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wuskwatim - Generation			41	13	15					
Keeyask - Generation	(26)	80	375	13	67	310	142	(100)	19	
Conawapa - Generation	(74)	(26)	(24)	(157)	(214)	(297)	(323)	(765)	(1 230)	(1 223)
Kelsey Improvements & Upgrades			14		13					
Kettle Improvements & Upgrades	(20)	(18)	(14)	16	17	14	24	22		
Pointe du Bois Spillway Replacement	(23)	137	37	39						
Pointe du Bois - Transmission				17	14					
Gillam Redevelopment and Expansion Program (GREP)			20	22	23	22	20	19	21	21
Bipole III - Transmission Line	(28)	(81)	(127)		142	420	75			
Bipole III - Converter Stations	(62)	(171)	(110)	227	472	344	136	18		
Bipole III - Collector Lines	(53)	(21)	36	50	33	27				
Bipole III - Community Development Initiative		54								
Riel 230/500kV Station	16	26	36							
Firm Import Upgrades	(20)									
Manitoba-Minnesota Transmission Project				29	66	(25)	(13)	48	35	
Demand Side Management		26	52	59	77	84	94	78	73	61
Generating Station Improvements & Upgrades									(12)	
CEF14 MNG&T Target Adjustment (Cost Flow)	118	(85)	(116)	(11)	115	(290)	194	149	77	29
Pine Falls Units 1-4 Major Overhauls	(15)	(23)	(32)	(45)	12	26	30	41		
Jenpeg Overhaul Program						(18)	(24)	(24)	(25)	(21)
Slave Falls Major Overhauls			(23)	(31)	(35)	(31)				19
Pointe du Bois GS Rehabilitation	(16)			15	47	50	25		11	
Great Falls Unit 4 Overhaul	(17)		16	14						
Brandon Units 6 & 7 "C" Overhaul Program										17
Rockwood East 230/115kV Station		13	27	11						
Lake Winnipeg East System Improvements		(11)	(15)	22						
Letellier - St. Vital 230kV Transmission					37	14				
Transmission Line Upgrades for NERC Alert							23	24	24	25
Dorsey 230kV Phase II Zone Building		(16)	(33)	(13)						
Bipole 2 Thyristor Valve Replacement							13	23	57	58
New Madison Station - 115/24kV Station			23	12	(11)					
St. Vital Station - 115/24kV Station					20	20				
Dawson Road Station - 115/24kV Station						17	20			
Burrows New 66/12kV Station	13	11								
New Adelaide Station - 66/12kV				21	23					

Variance MH14 vs MH11-2

Capital Expenditures (in millions of dollars)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Conawapa - Generation	(1 043)	(910)	(692)	(281)	(41)					
Pointe du Bois Powerhouse Rebuild		(16)	(38)	(91)	(158)	(245)	(404)	(313)	(216)	(53)
Gillam Redevelopment and Expansion Program (GREP)	19	25	24	26						
Demand Side Management	50	50	48	48	47	47	48	50	52	54
Generating Station Improvements & Upgrades	13	26	21	21	19	(47)	(36)	(53)	(160)	(97)
Additional North South Transmission				(318)						(57)
CEF14 MNG&T Target Adjustment (Cost Flow)	11		(306)	319						
Jenpeg Overhaul Program				21	22	23		45		
Slave Falls Major Overhauls	19	20	20	21	21					
Brandon Units 6 & 7 "C" Overhaul Program		19								
Transmission Line Upgrades for NERC Alert	28									
Bipole 2 Thyristor Valve Replacement	59	22								

Section:	Tab 3: Appendix 3.3	Page No.:	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

Please provide a schedule that compares the total annual electric new in-service additions in IFF11-2 with those in IFF14 for the years 2011/12 through 2031/32. Please include actuals for 2011/12 – 2013/14 when setting out the values for IFF14.

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

Please see the following table which compares the in-service additions between MH14 and MH11-2 for the years 2012/13 to 2031/32. MH11-2 incorporated actual in-service additions for 2011/12 resulting in no variance for that fiscal year and has been excluded from this comparison.

In-Service Amounts (in millions of dollars)	MH14	MH11-2	MH14 minus MH11-2
2013	2 335	1 435	900
2014	530	491	39
2015	1 700	1 135	565
2016	833	539	294
2017	1 283	583	700
2018	901	3 392	(2 491)
2019	5 007	456	4 552
2020	3 527	3 725	(198)
2021	4 773	2 815	1 958
2022	731	323	408
2023	617	367	251
2024	723	526	197
2025	670	4 372	(3 702)
2026	713	4 032	(3 319)
2027	854	1 216	(362)
2028	701	586	115
2029	722	523	198
2030	680	479	201
2031	728	1 972	(1 244)
2032	745	669	76

Section:	Tab 3: Appendix 3.3	Page No.:	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

With respect to the response to part (c), please identify those capital projects that account for $10 M or more of the variance between the in-service additions in any given year.

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

Please see the following table with in-service additions variances greater than $10 million between MH14 and MH11-2. MH11-2 incorporated actual in-service additions for 2011/12 resulting in no variance for that fiscal year and has been excluded from this comparison.

Variance MH14 vs MH11-2

In-Service (in millions of dollars)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wuskwatim - Generation	451	12	40		26					
Wuskwatim - Transmission	318									
Keeyask - Generation								(549)	1 325	83
Grand Rapids Fish Hatchery Upgrade & Expansion						24				
Conawapa - Generation					397					
Kelsey Improvements & Upgrades	(10)		17		15					
Kettle Improvements & Upgrades		(14)	(38)	16	16	18	24	22		
Pointe du Bois Spillway Replacement			138	91	(55)					
Pointe du Bois - Transmission			(27)	(24)		28				
Gillam Redevelopment and Expansion Program (GREP)			18	24	24	22	18	22	22	21
Bipole III - Transmission Line			19	13	11	(1 128)	1 487			
Bipole III - Converter Stations			14			(1 626)	2 452	18		
Bipole III - Collector Lines	(11)				13	(174)	237			
Bipole III - Community Development Initiative							62			
Riel 230/500kV Station			63							
Firm Import Upgrades	(20)									
Manitoba-Minnesota Transmission Project								(92)	240	
Demand Side Management		26	52	59	77	84	94	78	73	61
Generating Station Improvements & Upgrades									(12)	
Pine Falls Units 1-4 Major Overhauls		(43)	(15)	(65)		27	33	61		
Jenpeg Overhaul Program						(23)	(20)	(20)	(39)	(14)
Slave Falls Major Overhauls			(20)	(31)	(44)	(31)		16		32
Pointe du Bois GS Rehabilitation	(14)	(16)			19	58	55	12	12	
Great Falls Unit 4 Overhaul	(43)			53						
Rockwood East 230/115kV Station				53						
Lake Winnipeg East System Improvements				(67)	64					
Letellier - St. Vital 230kV Transmission						57				
Transmission Line Upgrades for NERC Alert							23	24	24	25
HVDC Dorsey Synchronous Condenser Refurbishment					(11)					
Dorsey 230kV Phase II Zone Building				(30)	(30)					
Bipole 2 Thyristor Valve Replacement									58	58
New Madison Station - 115/24kV Station				58	(40)					
St. Vital Station - 115/24kV Station							51			
Dawson Road Station - 115/24kV Station								49		
Burrows New 66/12kV Station			27							
New Adelaide Station - 66/12kV					45			17		

Variance MH14 vs MH11-2

In-Service (in millions of dollars)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Conawapa - Generation			(3 893)	(3 102)	(776)					
Pointe du Bois Powerhouse Rebuild							(64)		(1 419)	(56)
Gillam Redevelopment and Expansion Program (GREP)	20	19	22	30						
Demand Side Management	50	50	48	48	47	47	48	50	52	54
Generating Station Improvements & Upgrades	13	26	21	21	19	(36)	(23)	(35)	14	(179)
Additional North South Transmission				(318)						
Jenpeg Overhaul Program				23		20	20	39		14
Slave Falls Major Overhauls		32		32		16				
Brandon Units 6 & 7 "C" Overhaul Program		50								
Transmission Line Upgrades for NERC Alert	28									
Bipole 2 Thyristor Valve Replacement	58	58								

Section:	Tab 3: Appendix 3.3	Page No.:	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

Has the implementation of IFRS (e.g. reduced overhead capitalization) been incorporated into the current capital expenditure forecast? If so, has it been reflected in the individual capital project cost and for which years has this been done?

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

The impact of the transition to IFRS is reflected in the current capital expenditure forecast and individual capital projects from fiscal 2015/16 to 2033/34.

Section:	Tab 3: Appendix 3.3	**Page No.:**	22-25
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Sensitivity Analysis		
Issue:	Changes in Load Growth		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the discussion on Domestic Load Growth Sensitivity, do unit domestic revenues continue to be higher than opportunity export prices during the entire 20-year period of the IFF? If not, when does the turn-around occur?

RATIONALE FOR QUESTION:

The Information Request explores the impact of changes in load growth on Manitoba Hydro's financial results and goes to the credibility of Hydro's analysis and forecasts.

RESPONSE:

Average export unit revenues, including dependable and opportunity, are expected to be lower than average domestic unit revenues, including additional 3.95% proposed and indicative rate increases, throughout the 20-year forecast period to 2033/34 under both low and high domestic load scenarios.

Section:	Tab 3: Appendix 3.3	**Page No.:**	22-25
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Sensitivity Analysis		
Issue:	Changes in Load Growth		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the discussion on Domestic Load Growth, why are the opportunity export sales compared with domestic revenue? If domestic load decreases wouldn't this free up dependable capacity for additional dependable exports (assuming no change to the supply plan)?

RATIONALE FOR QUESTION:

The Information Request explores the impact of changes in load growth on Manitoba Hydro's financial results and goes to the credibility of Hydro's analysis and forecasts.

RESPONSE:

In the discussion on the domestic load growth sensitivity, opportunity sales are compared with domestic revenue as a point of reference only. The statement is correct that domestic load decreases that free up dependable capacity would be available to sell as a dependable exports and the sensitivity reflects this as additional uncommitted sales and these are priced in the sensitivity at a premium over opportunity prices.

Section:	Tab 3: Appendix 3.3	**Page No.:**	22-25
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Sensitivity Analysis		
Issue:	Changes in Load Growth		

PREAMBLE TO IR (IF ANY):

QUESTION:

Are the unit revenues from new dependable exports expected to be greater or less than domestic unit revenues over the first 10 years?

RATIONALE FOR QUESTION:

The Information Request explores the impact of changes in load growth on Manitoba Hydro’s financial results and goes to the credibility of Hydro's analysis and forecasts.

RESPONSE:

Average export unit revenues, including dependable and opportunity, are expected to be lower than average domestic unit revenues, including additional 3.95% proposed and indicative rate increases, throughout the 20-year forecast period to 2033/34 under both low and high domestic load scenarios.

Section:	Tab 3: Appendix 3.5	Page No.:	
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Alternate Rate Scenarios		
Issue:	Acceptable Financial Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

The discussion on page 2 appears to suggest that Scenarios C & D are unacceptable as they lead to equity levels below cost of five-year drought and that the proposed 3.95%/annum rate increase is acceptable from a financial strength perspective because the resulting retained earnings continue to exceed the cost of a five-year drought. Please comment on this interpretation of the discussion regarding the various scenarios.

RATIONALE FOR QUESTION:

To gain a better understanding of Manitoba Hydro's assessment of the varioius rate increase scenarios.

RESPONSE:

Alternative Rate Scenarios C & D result in a significant deterioration in Manitoba Hydro's financial position as indicated by the weak financial ratios as well as retained earnings. Manitoba Hydro continues in Appendix 3.5 at page 2, "This level of deterioration indicates that projected cash flows under Scenarios C and D, are not sufficient to fund Manitoba Hydro's operations or sustaining capital program and result in incremental borrowing at an unsustainable rate. Customers would be at significant risk of a rate shock, particularly if a drought or catastrophic infrastructure loss occurred."

From a financial strength perspective, the minimum 3.95% projected annual rate increases result in cumulative losses of more than $900 million assuming projected average revenues under all flow conditions. In the event of a sudden financial loss to Manitoba Hydro during this period of losses, it would not be financially prudent to allow retained earnings or financial ratios to deteriorate even further from that projected in MH14 and customers would bear the costs of such a financial loss. However, Manitoba Hydro has indicated that, "Despite the increased risk of higher than projected rate increases in the future, Manitoba Hydro has maintained the proposed rate increases at the 3.95% level in consideration of customer sensitivity to rate increases."

Section:	Tab 3: Appendix 3.6	Page No.:	
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Sensitivity Analysis Scenarios		
Issue:	Sensitivity Analysis Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the high and low load growth scenarios are both calculated using the same capital expenditure plan and overall supply plan as in IFF14. If not, what adjustments are made for each?

RATIONALE FOR QUESTION:

Information is required to better understand the basis for Manitoba Hydro's sensitivity analyses.

RESPONSE:

Confirmed.

Section:	Tab 3: Appendix 3.6	Page No.:	
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Sensitivity Analysis Scenarios		
Issue:	Sensitivity Analysis Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Manitoba Hydro has not provided the forecast financial statements of all of the cases summarized on page 1. Please provide the missing statements.

RATIONALE FOR QUESTION:

Information is required to better understand the basis for Manitoba Hydro's sensitivity analyses.

RESPONSE:

There are no missing statements as Manitoba Hydro has provided projected Income Statements, Balance Sheets and Cash Flow Statements for all of the cases identified on page 1 of Appendix 3.6, namely:

- Domestic load growth (Low and High)
- Interest rates (+1% and -1%)
- Foreign exchange rates (C$/US$ -0.10 and +0.10)
- Export prices (Low and High)
- Capital expenditures (-$50 million and + $50 million)
- Water flow conditions (5 year drought)
- Rate Increases (+1% and -1%)

Section:	Tab 4 Appendix 4.1	**Page No.:**	4 & 13-15 3-8
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital In-Service		
Issue:	Continuity Schedule		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the annual capital expenditures and total project costs shown in Tab 4 and Appendix 4.1 include interest during construction?

RATIONALE FOR QUESTION:

Information is required in order to better understand the impact of the forecast capital expenditures on Manitoba Hydro's financial outlook. More detailed analysis on depreciation will be left to MIPUG and PUB IRs 1-38 to 1-46.

RESPONSE:

Confirmed.

Section:	Tab 4 Appendix 4.1	Page No.:	4 & 13-15 3-8
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital In-Service		
Issue:	Continuity Schedule		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a revised version of Figure 4.1 that includes the actuals for 2011/12 through 2013/14 and the individual annual values out to 2023/24.

RATIONALE FOR QUESTION:

Information is required in order to better understand the impact of the forecast capital expenditures on Manitoba Hydro's financial outlook. More detailed analysis on depreciation will be left to MIPUG and PUB IRs 1-38 to 1-46.

RESPONSE:

Please see the following table.

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Major New Generation & Transmission	**568**	**600**	**984**	**1 452**	**1 914**	**2 463**	**2 578**	**1 531**	**884**	**426**	**196**	**117**	**110**
Sustaining Capital (Major & Base)	**465**	**433**	**470**	**571**	**577**	**610**	**547**	**547**	**548**	**573**	**555**	**563**	**571**
Generation Operations	123	104	116	132	132	132	132	132	132	132	135	137	140
Transmission	116	104	103	125	125	125	125	125	125	150	150	150	150
Customer Service & Distribution	172	175	186	236	241	268	206	206	206	206	210	214	219
Customer Care & Marketing	3	3	3	3	4	4	4	4	4	4	4	4	4
Human Resources & Corporate Services	51	46	63	75	75	55	55	55	55	55	56	57	58
Finance & Regulatory	-	0	0	0	0	0	0	0	0	0	0	0	0
Target Adjustment	-	-	-	-	-	25	25	25	25	25	-	-	-
Total Electric	**1 033**	**1 033**	**1 454**	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**

Section:	Tab 4 Appendix 4.1	**Page No.:**	4 & 13-15 3-8
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital In-Service		
Issue:	Continuity Schedule		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a continuity schedule based on IFF14 (Electric Operations) that for the years 2014/15 through 2033/34 shows for each of Major New G&T, Major Capital and Base Capital:

i. Total assets in-service (gross), accumulated depreciation, net assets-in-service and construction work-in-progress (CWIP) at the start of the year,
ii. The capital spending during the year (per CEF14),
iii. The assets placed in service during the year,
iv. The assets retired during the year along with associated accumulated depreciation,
v. Annual deprecation,
vi. The assets in service (gross), accumulated depreciation, net assets-in-service and CWIP at year end which will also be the values for the start of the next year. Note: CWIP at year end should equal CWIP at the start of the year, less assets place in service, plus capital expenditures for the year.

RATIONALE FOR QUESTION:

Information is required in order to better understand the impact of the forecast capital expenditures on Manitoba Hydro’s financial outlook. More detailed analysis on depreciation will be left to MIPUG and PUB IRs 1-38 to 1-46.

RESPONSE:

The attached schedule provides a continuity of MH14 Electric Operations Construction in Progress, Plant in Service and Accumulated Depreciation for the years 2014/15 through 2033/34.

A continuity schedule for Major New Generation and Transmission Construction in Progress is provided in PUB/MH-I-17a. Continuity schedules based on Major New Generation and Transmission (Plant in Service and Accumulated Depreciation), Major Capital and Base Capital are not available as Manitoba Hydro's financial systems track assets by cost element and depreciation category. As a result, opening balances at April 1, 2014, for Plant in Service, Construction in Progress (excluding Major New Generation and Transmission) and Accumulated Depreciation cannot be determined.

MH14 Net Plant in Service Continuity Schedule (In Millions of Dollars)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CEF14 Electric Operations Capital Expenditures	2 023	2 491	3 073	3 125	2 078	1 432	999	751	679	681
Contributions	36	29	29	30	31	31	32	32	33	34
Regulated, Deferred and Intangible Assets	(61)	(63)	(84)	(88)	(100)	(87)	(76)	(62)	(47)	(50)
Capital Expenditures to Construction in Progress	1 998	2 456	3 019	3 068	2 009	1 375	955	722	666	665
MH14 Construction in Progress, Opening Balance	2 939	3 257	4 932	6 755	8 982	6 040	3 939	169	185	240
Capital Expenditures	1 998	2 456	3 019	3 068	2 009	1 375	955	722	666	665
Additions to Plant in Service	(1 667)	(789)	(1 202)	(848)	(4 956)	(3 362)	(4 570)	(629)	(618)	(650)
Additions to Keeyask Deferred	-	-	-	-	-	(121)	(161)	(83)	-	-
Salvage to Accumulated Depreciation	(12)	7	6	7	6	6	7	7	7	7
MH14 Construction in Progress, Closing Balance	3 257	4 932	6 755	8 982	6 040	3 939	169	185	240	263
MH14 Plant in Service, Opening Balance	15 470	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478
Additions from Construction in Progress	1 667	789	1 202	848	4 956	3 362	4 570	629	618	650
Other Additions	26	15	13	13	13	13	300	14	14	15
Write-Off Ineligible Overhead under IFRS	-	(54)	-	-	-	-	-	-	-	-
MH14 Plant in Service, Closing Balance	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
MH14 Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Amortization of Regulated, Deferred and Intangible Assets	(67)	(69)	(71)	(73)	(75)	(81)	(93)	(101)	(103)	(105)
Amortization of Customer Contributions	14	15	16	16	17	18	18	19	19	19
Amortization of Bipole III Deferral Account	-	-	-	-	-	54	54	54	-	-
Depreciation on Common Assets to Gas	4	4	5	5	5	5	5	5	5	5
Corporate Allocation	2	2	2	2	2	2	2	1	1	1
Depreciation Expense to Accumulated Depreciation	359	353	374	396	470	521	598	645	659	673
MH14 Accumulated Depreciation, Opening Balance	5 329	5 676	6 012	6 392	6 795	7 270	7 798	8 403	9 055	9 721
Depreciation Expense	359	353	374	396	470	521	598	645	659	673
Salvage from Construction in Progress	(12)	7	6	7	6	6	7	7	7	7
Write-Off of Asset Removal Costs	-	(24)	-	-	-	-	-	-	-	-
MH14 Accumulated Depreciation, Closing Balance	5 676	6 012	6 392	6 795	7 270	7 798	8 403	9 055	9 721	10 401
Net Plant In Service	**11 487**	**11 900**	**12 735**	**13 193**	**17 687**	**20 535**	**24 800**	**24 791**	**24 757**	**24 741**

MH14 Net Plant in Service Continuity Schedule (In Millions of Dollars)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CEF14 Electric Operations Capital Expenditures	729	735	735	730	745	726	770	782	822	910
Contributions	34	35	36	37	37	38	39	40	40	41
Regulated, Deferred and Intangible Assets	(48)	(48)	(47)	(47)	(48)	(46)	(52)	(54)	(52)	(59)
Capital Expenditures to Construction in Progress	716	722	724	719	734	717	757	767	810	892
MH14 Construction in Progress, Opening Balance	263	322	343	225	254	277	323	365	402	465
Capital Expenditures	716	722	724	719	734	717	757	767	810	892
Additions to Plant in Service	(664)	(707)	(850)	(698)	(719)	(680)	(723)	(739)	(755)	(1 111)
Additions to Keeyask Deferred	-	-	-	-	-	-	-	-	-	-
Salvage to Accumulated Depreciation	7	7	8	8	8	8	8	8	9	9
MH14 Construction in Progress, Closing Balance	322	343	225	254	277	323	365	402	465	255
MH14 Plant in Service, Opening Balance	35 142	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823
Additions from Construction in Progress	664	707	850	698	719	680	723	739	755	1 111
Other Additions	15	15	15	16	16	16	17	17	17	18
Write-Off Ineligible Overhead under IFRS	-	-	-	-	-	-	-	-	-	-
MH14 Plant in Service, Closing Balance	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
MH14 Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Amortization of Regulated, Deferred and Intangible Assets	(106)	(105)	(102)	(98)	(93)	(89)	(86)	(83)	(82)	(84)
Amortization of Customer Contributions	20	21	21	22	23	23	24	25	25	26
Amortization of Bipole III Deferral Account	-	-	-	-	-	-	-	-	-	-
Depreciation on Common Assets to Gas	5	6	6	6	6	6	6	6	6	6
Corporate Allocation	1	1	1	1	1	1	1	1	1	1
Depreciation Expense to Accumulated Depreciation	688	703	718	735	748	762	776	791	807	823
MH14 Accumulated Depreciation, Opening Balance	10 401	11 096	11 807	12 532	13 274	14 030	14 800	15 585	16 384	17 200
Depreciation Expense	688	703	718	735	748	762	776	791	807	823
Salvage from Construction in Progress	7	7	8	8	8	8	8	8	9	9
Write-Off of Asset Removal Costs	-	-	-	-	-	-	-	-	-	-
MH14 Accumulated Depreciation, Closing Balance	11 096	11 807	12 532	13 274	14 030	14 800	15 585	16 384	17 200	18 031
Net Plant In Service	**24 725**	**24 737**	**24 878**	**24 849**	**24 828**	**24 754**	**24 710**	**24 666**	**24 623**	**24 921**

Section:	Tab 4 Appendix 4.1	Page No.:	9 10
Topic:	Capital Expenditure Forecast		
Subtopic:	Major Generation Projects		
Issue:	Capital Cost Details and Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

What was the total project cost for Keeyask as provided in the last update in the NFAT proceeding? Please also provide the reference as to where in the NFAT record the cost estimate is found.

RATIONALE FOR QUESTION:

The information request seeks to better understand the current capital expenditure forecasts for Keeyask and Conawapa. Forecast capital is central to the rate application. The question is distinct from PUB/MH 1-23 and 1-24.

RESPONSE:

The control budget for the Keeyask Project is $6.5 billion. This information was presented at the NFAT hearings as Manitoba Hydro Exhibit 95 – slide 101 and Manitoba Hydro Exhibit 109.

Section:	Tab 4 Appendix 4.1	Page No.:	9 10
Topic:	Capital Expenditure Forecast		
Subtopic:	Major Generation Projects		
Issue:	Capital Cost Details and Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an explanation of any variance between this value and the cost estimate for Keeyask per CEF14.

RATIONALE FOR QUESTION:

The information request seeks to better understand the current capital expenditure forecasts for Keeyask and Conawapa. Forecast capital is central to the rate application. The question is distinct from PUB/MH 1-23 and 1-24.

RESPONSE:

There is no variance between the project cost presented at the NFAT and CEF14. The total Keeyask Project budget in CEF14 remains at $6.5 billion, consistent with what was filed and discussed during the NFAT.

Section:	Tab 4 Appendix 4.1	**Page No.:**	9 10
Topic:	Capital Expenditure Forecast		
Subtopic:	Major Generation Projects		
Issue:	Capital Cost Details and Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that sets out the annual spending, both historic and projected for Conawapa.

RATIONALE FOR QUESTION:

The information request seeks to better understand the current capital expenditure forecasts for Keeyask and Conawapa. Forecast capital is central to the rate application. The question is distinct from PUB/MH 1-23 and 1-24.

RESPONSE:

See table on the following page for annual spending for Conawapa.

	Actual Costs	**Forecasted Costs**	Total
2004	**0.20**		0.20
2005	**8.48**		8.48
2006	**28.10**		28.10
2007	**32.64**		32.64
2008	**34.03**		34.03
2009	**33.43**		33.43
2010	**35.17**		35.17
2011	**29.72**		29.72
2012	**28.20**		28.20
2013	**30.73**		30.73
2014	**40.50**		40.50
2015 (April to December)	**28.51**		
2015 (January to March)		**14.90**	43.40
2016		**31.40**	31.40
2017		**21.00**	21.00
Total	**329.71**	67.30	**397.00**

Note: the values above include capitalized interest costs.

Section:	Tab 4 Appendix 4.1	**Page No.:**	9 10
Topic:	Capital Expenditure Forecast		
Subtopic:	Major Generation Projects		
Issue:	Capital Cost Details and Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

What was the total spent to date for Conawapa as provided in last update in the NFAT proceeding? Please also provide the reference as to where in the NFAT record this value is found.

RATIONALE FOR QUESTION:

The information request seeks to better understand the current capital expenditure forecasts for Keeyask and Conawapa. Forecast capital is central to the rate application. The question is distinct from PUB/MH 1-23 and 1-24.

RESPONSE:

The Manitoba Hydro NFAT business case used actual costs as of March 31, 2012 of $0.23B (including interest). Subsequently, an update of actual costs to December 31, 2013 of $0.29B (including interest) was provided in MH Exhibit #109.

Section:	Tab 4	Page No.:	10-12
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Spending for System Extensions		

PREAMBLE TO IR (IF ANY):

QUESTION:

Are any of the Major or Base Capital Expenditures set out in CEF14 being made for purposes of extending either the transmission or distribution systems so as to serve new customers? If yes, please provide a schedule that identifies the related projects and their annual costs.

RATIONALE FOR QUESTION:

The information request seeks to better understand the basis for Manitoba Hydro's Sustaining Capital Expenditures related to system expansion/new customers.

RESPONSE:

There is approximately $40 million annually in Base Capital Expenditures set out in the CEF14 for the purposes of extending the distribution system to serve new customers. The programs include overhead and underground service extensions to residential and commercial customers.

There are no Major or Base Capital Expenditures set out in the CEF14 for the purposes of extending the transmission system to serve new customers. All expenditures set out in CEF14 are to address requirements for normal forecasted load growth.

Section:	Tab 4	**Page No.:**	10-12
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Spending for System Extensions		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the response to part (a) is affirmative:

i. What is Manitoba Hydro's policy with respect to requiring capital contributions from customers in such circumstances?

ii. What assumptions has Manitoba Hydro made regarding customer capital contributions associated with CEF14 and what was the basis for these assumptions?

iii. How are such contributions treated in CEF14 and IFF14?

RATIONALE FOR QUESTION:

The information request seeks to better understand the basis for Manitoba Hydro's Sustaining Capital Expenditures related to system expansion/new customers.

RESPONSE:

Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either the specified investment allowance (in the case of residential customers) or the amount of investment allowance as determined by a revenue test (in the case of General Service customers served at voltages less than 30 kV). General Service customers requiring service at voltages greater than 30 kV, or any new General Service load greater than 5 MW, contribute to the full cost of the dedicated service extension facilities and capacity additions to the common integrated system, if required.

Generally, contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

Section:	Tab 4	**Page No.:**	12
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital		
Issue:	Historical Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a revised version of Figure 4.12 that includes the actual spending by asset type for 2011/12, 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

The information requests seeks to better understand those areas where expenditures on Sustaining Capital are increasing. The question is distinct from PUB/MH 1-18, 1-19.

RESPONSE:

Please refer to Manitoba Hydro's response to COALITION/MH-I-85e.

Section:	Tab 4	**Page No.:**	15
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Capital Spending Deferrals		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page 15 (lines 7-8), please describe more fully how Manitoba Hydro's asset management has enabled it to defer hundreds of millions of dollars of capital investment to date.

RATIONALE FOR QUESTION:

The information request seeks to better understand Manitoba Hydro's asset management practices and their effect on spending. It goes to the prudence of expenditures. It poses distinct questions from PUB/MH 1-19.

RESPONSE:

Please see the response to PUB/MH-I-18d.

Section:	Tab 4	**Page No.:**	15
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Capital Spending Deferrals		

PREAMBLE TO IR (IF ANY):

QUESTION:

Precisely what investments have been deferred and over what period?

RATIONALE FOR QUESTION:

The information request seeks to better understand Manitoba Hydro's asset management practices and their effect on spending. It goes to the prudence of expenditures. It poses distinct questions from PUB/MH 1-19.

RESPONSE:

The deferral of Manitoba Hydro's replacement of assets is broad based and as illustrated in Tab 4 Figure 4.18, consists of most categories of assets it maintains for ongoing reliable service. Most asset categories illustrated in Figure 4.18 have current turnover rates that exceed the average life of its assets. These replacement rates reflect normal practice for the last several years and up to the present time have yielded positive results in maintaining system reliability considering the overall financial impact on financial targets, debt financing requirements and customer rates. The age of the electric plant is now reaching a stage where these programs will diminish in effectiveness.

Please also refer to the response to PUB/MH-I-18d.

Section:	Tab 4	**Page No.:**	16-17
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Spending		
Issue:	Reliability Trends		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Figure 4.15, how do Manitoba Hydro's outage rates for hydro-electric generation compare with those for other CEA utilities?

RATIONALE FOR QUESTION:

The information request seeks to better understand the historic reliabilty trends reported. The issues go to the prudence and reasonableness of expenditures.

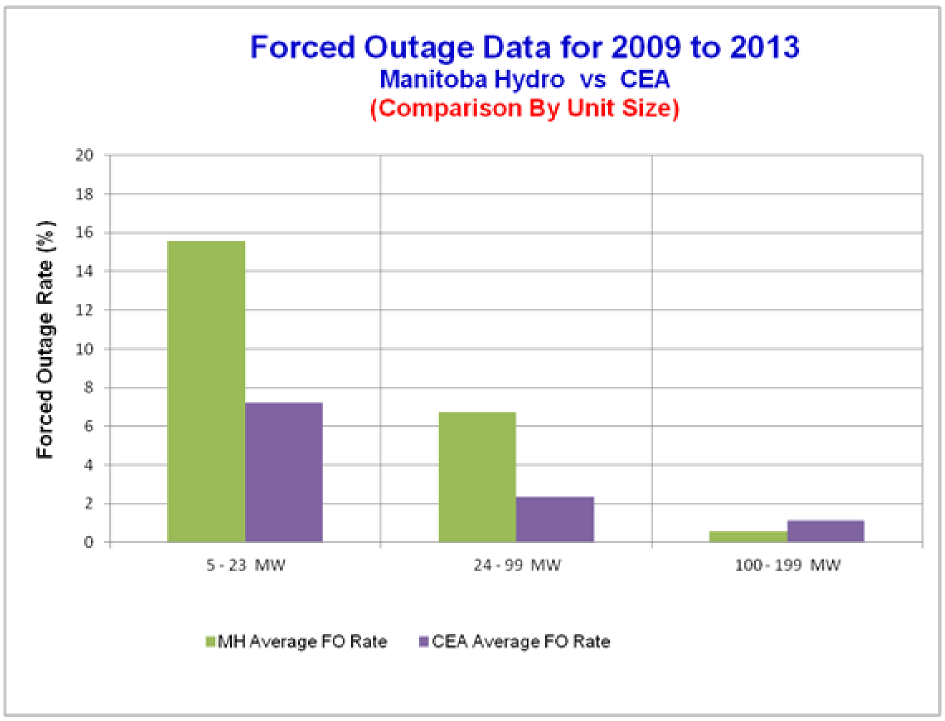
RESPONSE:

Figure 4.15 plots the Weighted Forced Outage Rate which factors in the size of the generating unit, as outages of larger units have greater financial impact. Manitoba Hydro compared the Forced Outage Data with the five years (2009 – 2013) of CEA data available in their latest report. For this 5 year period, Manitoba Hydro's actual average Weighted Forced Outage Rate is 2.6%. Comparative weighted Forced Outage rates from CEA are not available.

However, Manitoba Hydro's actual average Forced Outage Rate during this 5 year period was 9.7% while the CEA corresponding actual average Forced Outage Rate for this same time period (based on 472 unit survey) is 4.1%.

While the Manitoba Hydro average Forced Outage Rate is significantly higher than that of the CEA survey, this is not consistent for all unit sizes which explains the large difference between weighted and actual data. The chart below shows the Forced Outage Rate data for this 5 year period as a function of Unit size. Essentially, the Manitoba Hydro larger units are still performing better than the CEA survey.

These results can be explained as units below 100 MWs in size are the older units in the south of the province (Winnipeg River and JenPeg). The generating units in the north are greater than 100 MWs and no older than 45 years which is about middle age for a hydraulic generating unit when aging asset reliability problems are just beginning.



Section:	Tab 4	**Page No.:**	16-17
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Spending		
Issue:	Reliability Trends		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Figure 4.15, what hydraulic stations contributed to the higher forced outage rates in 2010-2014?

RATIONALE FOR QUESTION:

The information request seeks to better understand the historic reliabilty trends reported. The issues go to the prudence and reasonableness of expenditures.

RESPONSE:

The table below shows the average (non-weighted) Forced Outage Rate for each of the years along with the Forced Outage Rate for each station. Essentially, Jenpeg and Pointe Du Bois are significant contributors each year with other stations falling into third place, depending on the year.

Table: Forced Outage Rate (%) for 2010 to 2014 - NON-WEIGHTED

2010		2011		2012		2013		2014	
Jenpeg	38.6	Poine Du Bois	46.8	Poine Du Bois	49.7	Poine Du Bois	43.2	Poine Du Bois	50.2
Poine Du Bois	30.5	Jenpeg	35.4	Jenpeg	29.3	Jenpeg	42.9	Jenpeg	45.5
Average	**7.7**	Slave Falls	19.4	Great Falls	20.3	Slave Falls	19.0	McArthur	18.2
Great Falls	5.7	**Average**	**12.4**	**Average**	**13.0**	Pine Falls	16.4	**Average**	**14.3**
Slave Falls	3.4	Seven Sisters	4.6	Slave Falls	6.5	**Average**	**13.2**	Pine Falls	13.3
Seven Sisters	2.9	Great Falls	3.3	Kettle	3.4	Great Falls	7.4	Slave Falls	7.3
McArthur	1.4	Pine Falls	2.6	Pine Falls	2.7	Kelsey	3.6	Great Falls	3.4
Pine Falls	1.3	Grand Rapids	0.9	Seven Sisters	0.7	Wuskwatim	3.5	Seven Sisters	1.8
Laurie River 1	0.4	Laurie River 1	0.8	Wuskwatim	0.6	Laurie River 2	2.6	Wuskwatim	0.6
Long Spruce	0.2	Kelsey	0.3	Grand Rapids	0.5	Grand Rapids	1.3	Grand Rapids	0.6
Kelsey	0.1	McArthur	0.3	Kelsey	0.4	McArthur	1.2	Kettle	0.6
Limestone	0.1	Laurie River 2	0.3	Long Spruce	0.3	Long Spruce	1.0	Limestone	0.6
Grand Rapids	0.0	Long Spruce	0.2	Limestone	0.3	Seven Sisters	0.7	Laurie River 2	0.3
Kettle	0.0	Kettle	0.1	Laurie River 1	0.3	Kettle	0.3	Kelsey	0.3
Laurie River 2	0.0	Limestone	0.1	Laurie River 2	0.2	Limestone	0.2	Long Spruce	0.1
Wuskwatim	na	Wuskwatim	na	McArthur	0.1	Laurie River 1	0.1	Laurie River 1	0.0

Section:	Tab 4	**Page No.:**	16-17
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Spending		
Issue:	Reliability Trends		

PREAMBLE TO IR (IF ANY):

QUESTION:

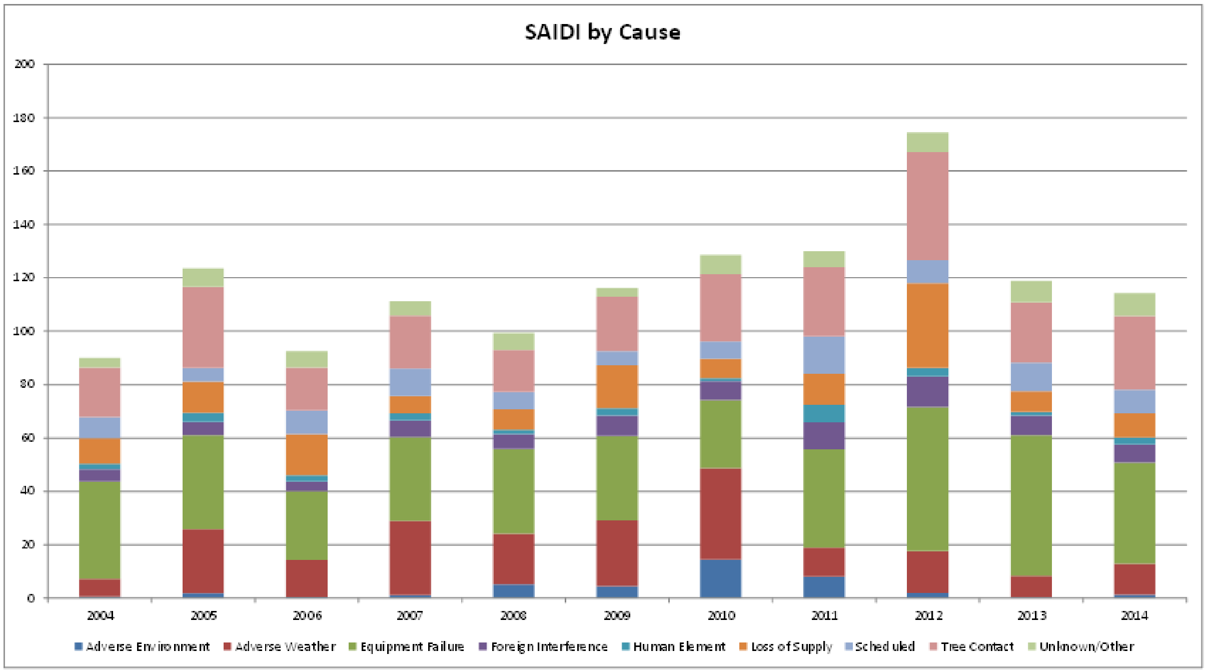
With respect to Figure 4.16 does Manitoba Hydro track the various causes of SIADI AND SAIFI? If so, please provide a breakdown of the historic (2004-2014) SAIDI and SAIFI values by cause.

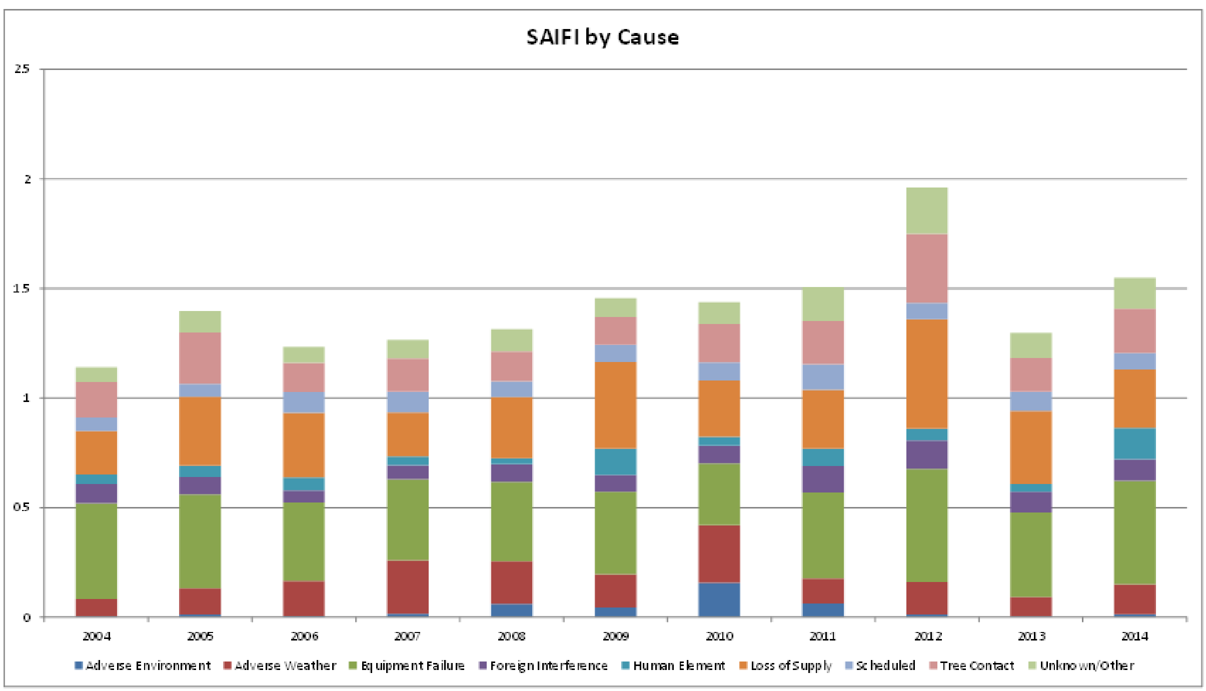
RATIONALE FOR QUESTION:

The information request seeks to better understand the historic reliabilty trends reported. The issues go to the prudence and reasonableness of expenditures.

RESPONSE:

Manitoba Hydro tracks the various causes of SAIDI and SAIFI; a summary of the breakdown of causes for the period 2004-2014 is provided below.





Definitions for the causes referenced in the SAIDI/ SAIFI charts are as follows:

- Scheduled Outage - Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
- Tree Contact - Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.
- Equipment Failure - Customer interruptions resulting from equipment failures due to deterioration from age, wear or imminent failures detected by maintenance.
- Adverse Weather - Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.
- Adverse Environment - Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire and flooding.
- Human Element - Customer interruptions due to operational issues involving incorrect records, equipment use, installations or protection settings. May also involve switching errors or unintentional damage.
- Foreign Interference - Customer interruptions beyond the control of the utility such as wildlife, vehicles, dig-ins, vandalism, sabotage and foreign objects.
- Loss of Supply - Customer interruptions due to problems in the bulk electricity supply system such as under-frequency load shedding, transmission system transients or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.
- Unknown/Other - Customer interruptions with no apparent cause or reason which could have contributed to the outage or that any outage that does not fit into any of the above categories.

Over the past decade, the leading factor contributing to outage frequency (SAIFI) performance has been equipment failure, which on average has been responsible for over 30% of outages. The second most prevalent contributor to SAIFI performance has been tree contact followed by adverse weather.

The greatest factor of outage duration performance (SAIDI) is also equipment failure and once again contributing over 30% of overall outage minutes. Tree contact is also a significant factor.

The failure of underground cables and wood poles are two asset categories that affect SAIDI and SAIFI performance to a significant degree. As the condition of these assets deteriorates, a direct consequence will be worsening reliability performance.

Section:	Tab 4 Tab 11	Page No.:	4 2
Topic:	Capital Expenditure Forecast		
Subtopic:	Electric Capital Spending		
Issue:	Forecast vs. Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

Tab 11, page 2 makes reference to sustaining capital "targets" being established in CEF14. Please confirm that the "targets" referred to are the budget/forecast values set out CEF14 and used in the IFF14.

RATIONALE FOR QUESTION:

Information request seeks to clarify the terminology used by Manitoba Hydro in its Application.

RESPONSE:

Confirmed.

Section:	Tab 5 Appendix 5.1	Page No.:	3 104
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Forecast versus Actual Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that contrasts the actual Statement of Income results for 2012/13 and 2013/14 (per Schedule 5.1.0) with the forecast in MH11-2 from the previous GRA for the same years.

RATIONALE FOR QUESTION:

To understand changes that have occurred for 2012/13 and 2013/14 since the last GRA. This goes to the reliability of short and medium term Hydro forecasts which are a central element of rate setting.

RESPONSE:

Please refer to COALITION/MH-I-13 b.

Section:	Tab 5 Appendix 5.1	Page No.:	3 104
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Forecast versus Actual Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a commentary that explains any material variances for each year.

RATIONALE FOR QUESTION:

To understand changes that have occurred for 2012/13 and 2013/14 since the last GRA. This goes to the reliability of short and medium term Hydro forecasts which are a central element of rate setting.

RESPONSE:

Please refer to COALITION/MH-I-13b.

Section:	Tab 5 Appendix 5.1	Page No.:	3 104
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Forecast versus Actual Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please reconcile the actual results shown in Schedule 5.1.0 for 2012/13 and 2013/14 with the results reported in the March 2014 Annual Report (Appendix 5.1) for the Electricity Segment.

RATIONALE FOR QUESTION:

To understand changes that have occurred for 2012/13 and 2013/14 since the last GRA. This goes to the reliability of short and medium term Hydro forecasts which are a central element of rate setting.

RESPONSE:

The differences in the actual revenues and expenses for 2013 and 2014 as reported in the Annual Report Segmented Information note and those shown in this Application result from the removal of revenues and expenses for the subsidiaries.

Please see the following table.

	2013 Annual Report	2013 Actuals Application	Difference	Reason
Total Revenue	1 763	1 723	(40)	Removal of Subsidiary Revenue
Operating, Maintenance and Administrative	469	463	(6)	Removal of Subsidiary Expense
Finance Expense	452	452	-	
Depreciation and Amortization	394	392	(2)	Removal of Subsidiary Depreciation
Water Rentals and Assessments	118	118	-	
Fuel and Power Purchased	133	133	-	
Capital and Other Taxes	87	86	(1)	Removal of Subsidiary Capital Tax
Corporate Allocation	9	9	-	
Other Expense	30	5	(25)	Removal of Subsidiary Expense
Total Expenses	1 692	1 658	(34)	
Non-controlling interest	13	13	-	
Net Income	84	78	(6)	

	2014 Annual Report	2014 Actuals Application	Difference	Reason
Total Revenue	1 914	1 866	(48)	Removal of Subsidiary Revenue
Operating, Maintenance and Administrative	490	481	(9)	Removal of Subsidiary Expense
Finance Expense	436	435	(1)	Rounding
Depreciation and Amortization	412	411	(1)	Removal of Subsidiary Depreciation
Water Rentals and Assessments	125	126	1	Rounding
Fuel and Power Purchased	177	177	-	
Capital and Other Taxes	97	97	-	
Corporate Allocation	9	9	-	
Other Expense	36	6	(30)	Removal of Subsidiary Expense
Total Expenses	1 782	1 742	(40)	
Non-controlling interest	22	22		
Net Income	154	146	(8)	

Section:	Tab 5	**Page No.:**	4
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Year over Year Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Page 4 (lines 5-9), was it outages on US or Manitoba transmission that limited exports and what was the cause of the outages?

RATIONALE FOR QUESTION:

To clarify the year over year variance explanations provided in the Application.

RESPONSE:

Exports were restricted on the US interface due to the 500 kV transmission line being taken out of service for work on the Riel reliability improvement project. This outage extended through the month of October. Additional transmission restrictions occurred for part of November associated with other transmission work in the US.

Section:	Tab 5	**Page No.:**	4
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Year over Year Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Did the reduced exports lead to increased hydraulic storage over the two months or was water spilt? If the later please explain why. If the former, why didn't the outages simply lead to higher exports in the subsequent months?

RATIONALE FOR QUESTION:

To clarify the year over year variance explanations provided in the Application.

RESPONSE:

To the extent possible, Manitoba Hydro managed its reservoir storage to minimize the amount of spilled energy associated with these transmission outages.

The transmission restrictions resulted in an increase in water spilled. Manitoba Hydro was spilling on the Nelson River before, during and following this transmission outage as outflows from Lake Winnipeg were at maximum discharge as the level was above elevation 715 feet. As a result there was no opportunity to store water in Lake Winnipeg and reduce spillage. During the outage when export capability was reduced, generation had to be reduced and spillage increased.

However, in anticipation of the outage Manitoba Hydro was able to adjust the generation schedule at Grand Rapids to minimize spill. Grand Rapids generation was increased during

August and September to establish storage room in Cedar Lake which enabled reduced generation and spill on the lower Nelson during the outage.

Section:	Tab 5	Page No.:	4
Topic:	Financial Results & Forecasts		
Subtopic:	Summary of Financial Results and Forecasts		
Issue:	Year over Year Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Page 4 (lines 25-28) indicates that the accounting changes as a result of transition to IFRS result in an overall reduction in net income in 2015/16. However, Appendix 5.7 (Figure 5.6.1) suggests that the accounting changes will reduce expenses by $4 M. Please reconcile.

RATIONALE FOR QUESTION:

To clarify the year over year variance explanations provided in the Application.

RESPONSE:

The transition to IFRS results in an overall reduction to net income for Electric operations of $24 million and includes the requirement to expense costs no longer eligible for capitalization, the change to IFRS compliant depreciation, the removal of negative salvage as well as changes in pension and other benefits. The reduction to net income as a result of IFRS changes is offset by a decrease in depreciation expense due to the implementation of new depreciation rates as part of Manitoba Hydro's most recent depreciation study. The revised depreciation rates reflect new service life estimates and are effective April 1, 2014.

Figure 5.6.1 of Appendix 5.7 demonstrates that the overall net impact of all accounting policy and estimate changes (including reductions in depreciation rates for service life changes), results in an increase to net income of $4 million in 2015/16. As such the collective accounting changes are not driving the need for customer rate increases.

The reference on page 4 (lines 25-28), which provides an analysis of the change in forecasted net income between the 2014/15 and 2015/16 fiscal years considers only the impacts of the IFRS changes as the reduction in depreciation expense is reflected in both the 2014/15 and 2015/16 fiscal years and does not have an impact on the difference in net income between the two years.

Section:	5	**Page No.:**	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update PUB/MH I-11 a) and b) (from the previous GRA) to include actual values for 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

Please see Figures 9.6, 9.8 and 9.9 of Tab 9 of the application for updated tables.

Section:	5	**Page No.:**	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update PUB/MH I-12 a) & b) (from the previous GRA) to include actual values for 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

Please see tables below.

Table 1. Export Revenues (excludes Merchant)	**2010/11**			**2011/12**			**2012/13**			**2013/14**		
	GWh	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**
Dependable												
Physical	3,138	161	5.1	3,490	163	4.7	3471	168	4.8	3413	179	5.2
Financial	239	12		253	12		165	9		66	3	
Dependable Total	3,377	172	5.1	3,743	175	4.7	3636	177	4.9	3479	181.7	5.2
Opportunity												
Bilateral												
Physical	1,608	45	2.8	1,535	40	2.6	1457	47	3.2	1335	47	3.5
Financial	243	7		388	10		243	6		135	6	
Opportunity Bilateral Total	1,851	52		1,923	50		1700	54		1470	53	
Market												
Day Ahead												
Physical	3,240	73	2.3	3,009	62	2.1	2814	61	2.2	4276	112	2.6
Financial	-8	-4		-290	-10		-267	-8		-26	-3	
Day Ahead Total	3,232	69	2.1	2,719	52	1.9	2547	52	2.1	4250	109	2.6
Real Time												
AESO	24	1		25	1		8	0		46	2	
IESO												
Energy	671	18		538	13		177	3		243	8	
Congestion Mgmnt. Settlement Credits		9			4			3			-1	
Inter-tie Offer Guarantee		1			3			3			2	
CMSC Clawbacks for prior years											-11	
MISO												
Real Time Physical	215	6		290	7		195	4		308	10	
Real Time Financial	4	0		10	0		14	0		17	1	
ASM Energy	970	24		997	20		809	20		722	21	
ASM Other (Reg, Spin, Supp, True-Ups)		2			1							
RT Total (only physical and energy related)	1,880	49	2.6	1,850	41	2.2	1189	28	2.3	1319	40	3.1
RT Total		60			50			35			31	
Total (only physical and energy related)	9,866	328	3.3	9,884	306	3.1	8,931	304	3.4	10,343	379	3.7
Total		353			327			318			374	

Table 2. Purchases (excludes Merchant)		**2010/11**			**2011/12**			**2012/13**			**2013/14**	
	GWh	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**
Dependable												
Physical	433	22	5.1	936	62	6.7	852	60	7.0	1,124	75	6.7
Financial	16	0		33	0		49	1		47	1	
Dependable Total	449	22	5.0	969	63	6.5	901	60	6.7	1,171	76	6.5
Opportunity												
Bilateral												
Physical	1	0.06	6.4	1	0.03	4.3	0	0.01	4.1	0	0.00	
Financial	7	-0.02		0	0.05		0	0.10		2	0.16	
Opportunity Bilateral Total	8	0		1	0.08		0	0.11		2	0.16	
Market												
Day Ahead												
Physical	128	2.5	2.0	215	3.0	1.4	432	10	2.2	256	9.76	3.8
Financial	19	0.1		10	0.2		14	0		17	1	
Day Ahead Total	147	2.6	1.8	225	3	1.4	446	10	2.3	273	10	3.8
Real Time												
IESO												
IESO Energy	15	0.3		20	0		42	0.792		126	4.23	
CMSC		-0.1			0			0.3			-5.4	
MISO												
Physical	60	2.6		72	3		52	2		70	4	
Financial	475	12.0		348	7		141	3		181	6	
RT Total (only physical and energy related)	75	3	3.9	92	3	3.2	94	3	3.3	196	8	4.3
RT Total		15			10			6			9	
Total (only physical and energy related)	637	28	4.3	1,244	68	5.5	0 1,378	73	5.3	1,576	93	5.9
Total	1,154	40		1,635	76		1,582	77		1,823	95	

Section:	5	**Page No.:**	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update MIPUG/MH I-27 b) & c) (from the previous GRA) to include: i) actual values for 2011/12 through 2013/14 and ii) forecast values for 2014/15 through 2016/17.

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

See Tables 1 and 2 below.

Table 1.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE

Schedule 5.1.2
(000's)
MH14

	2009/10		2010/11		2011/12		2012/13		2013/14		2014/15		2015/16		2016/17	
	Actual MWh	Actual$	Actual MWh	Actual$	Actual MWh	Actual$	Actual MWh	Actual$	Actual MWh	Actual$	Forecast MWh	Forecast $	Forecast MWh	Forecast $	Forecast MWh	Forecast $
Dependable Sales		$ -		$ -		$ -		$ -		$ -		$ -	60,800	$ 4,045		$ 12,659
Opportunity Sales	373,000	41,185	904,760	35,890	887,000	34,350	759,932	33,353	722,331	20,392	802,000	28,748	329,000	10,908	622,909	30,967
Canadian Sales		41,185		35,890		34,350		33,353		20,392		28,748		14,953		43,626
Other Sales		(226)		(81)		51		122		(40)		(54)		-		-
Canadian		40,959		35,809		34,401		33,475		20,352		28,694		14,953		43,626
Dependable Sales	3,262,976	185,967	3,377,506	172,362	3,742,000	174,872	3,636,463	177,049	3,478,885	181,674	3,181,000	177,157	3,444,500	205,795	2,278,182	193,641
Opportunities Sales	7,224,000	153,977	6,062,043	145,833	5,615,000	116,297	4,690,822	108,428	6,335,703	173,081	6,002,000	165,846	5,151,000	174,238	4,166,182	185,865
FV Chg Export Financial Contracts		806		(637)		489		(658)		551						
US Sales		338,492		315,940		291,658		284,819		355,306		343,003		380,033		379,506
Other Sales		2,258		1,618		682		4,973		8,722		6,468		5,688		572
Transmission Credits		17,710		16,402		17,559		18,307		18,021		17,443		22,140		23,841
Renewable Energy Certificates		1,076		1,116		2,032		1,942		3,494		3,045		2,299		2,193
US		359,536		335,076		311,931		310,041		385,543		369,959		410,160		406,112
Merchant (IESO & MISO)*		26,146		27,422		16,712		9,116		33,287		10,239		7,893		-
Total Extraprovincial Revenue		$ 426,641		$ 398,307		$ 363,044		$ 352,632		$ 439,182		$ 408,892		$ 433,006		$ 449,738
Water Rentals and Assessments		(103,973)		(106,169)		(145,632)		(133,292)		(125,517)		(124,469)		(122,847)		(112,167
Fuel and Power Purchased		(121,033)		(120,163)		(119,301)		(117,864)		(177,113)		(134,189)		(130,432)		(190,933
Net Extraprovincial Revenue		$ 201,635		$ 171,974		$ 98,111		$ 101,477		$ 136,552		$ 150,234		$ 179,727		$ 146,637

*IESO = Independent Electricity Systems Operator and MISO = Midcontinent Independent System Operator

Table 2.

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
US Sales in Canadian $	338,492	315,940	291,658	284,819	355,306	343,003	380,033	379,506
Average Yearly Exchange Rate	1.0846	1.0191	0.9895	1.0037	1.0553	1.0956	1.12	1.12
US Sales in US $	312,089	310,019	294,753	283,769	336,687	313,073	339,315	338,845

Section:	5	**Page No.:**	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update CAC/MH I-3 c) (from the previous GRA) to include actual values for 2012/13 and 2013/14.

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

Please see the information below.

MISO - Day Ahead MHEB LMP (US$/MWh)

	2007/08			2008/09			2009/10			2010/11		
Month	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average
April	70.84	41.77	55.34	65.77	33.81	49.43	25.72	14.29	19.88	25.29	16.1	20.59
May	59.58	24.68	41.2	52.94	21.78	35.85	23.08	11.39	16.42	31.98	22.08	26.33
June	59.03	23.37	40.01	56.15	18.45	36.04	22.84	10.73	16.65	31.55	18.47	24.87
July	67.52	28.16	45.93	79.48	24.28	50.39	23.14	10.91	16.96	37.88	21.56	28.93
August	61.55	23.46	42.3	61.68	24.93	41.52	25.45	12.24	18.21	41.69	22.94	31.81
September	46.15	20.46	31.31	43.76	20.55	31.38	24.02	12.86	18.07	27.14	13.78	20.01
October	52.4	22.65	37.37	42.63	18.82	30.6	31.02	16.72	23.48	29.16	16.89	22.43
November	61.99	26.93	43.27	45.71	23.27	32.73	26.91	15.8	20.73	26.71	15.75	20.85
December	73.51	46.27	57.99	60.19	33.69	46.23	41.07	24.63	32.41	34.81	22.82	28.75
January	67.44	38.72	52.31	48.15	30.39	38.41	46.07	31.1	37.54	35.74	25.37	30.05
February	75.63	44.02	59.28	36.08	23.85	29.67	43.29	28.72	35.65	30.4	18.63	24.24
March	76.61	48.46	61.19	29.04	18.12	23.29	29.45	20.35	24.86	29.51	18.94	24.17

	2011/12			2012/13			2013/14		
Month	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average
April	29.14	17.72	23.05	21.69	15.37	18.32	34.9	24.14	29.4
May	26.41	13.25	19.19	26.93	20.45	23.52	31.46	19.86	25.35
June	25.65	14.67	20.04	22.48	14.79	18.38	30.73	18.87	24.14
July	43.44	25.53	33.23	39.36	20.95	29.26	35.35	21.6	28.11
August	36.99	20.77	28.79	25.32	15.78	20.5	33.86	19.55	26.32
September	27.48	15.76	21.23	23.53	15.09	18.65	27.36	18.4	22.38
October	25	12.82	18.32	26.57	18.35	22.42	32.63	18.1	25.29
November	28.89	15.57	21.78	29.86	19.76	24.47	27.98	17.81	22.32
December	30.31	19.14	24.18	34.48	24.63	28.87	41.67	32.38	36.58
January	25.27	17.08	20.78	33.05	24.37	28.48	70.91	38.4	53.78
February	24.46	20.24	22.28	31.13	24.02	27.41	62.13	40.93	51.03
March	20.53	15.85	18.07	33.63	25.6	29.23	44.29	30.33	36.65

Note some values may have changed from those previously filed due to updates by MISO.

Section:	5	Page No.:	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain why Manitoba Hydro does not expect the same level of arbitrage opportunities between markets in 2014/15 as existed in 2013/14 (per page 12 – lines 1-2).

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

Manitoba Hydro's arbitrage opportunities between MISO and the IESO are a function of price differentials between the two markets. In 2013/14 higher than normal Merchant Revenues were achieved due to significant price spreads between the two markets. These price differentials for the most part were weather driven, with one major event being the polar vortex. The differentials forecast for 2014/15 are in line with historical averages and reflect normal price spreads between the two markets.

Section:	5	Page No.:	9-12
Topic:	Financial Results & Forecasts		
Subtopic:	Extra-Provincial Revenue		
Issue:	Actual and Forecast Export Prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain why Manitoba Hydro expects reduced participation in the IESO market and reduced arbitrage opportunities between markets in 2015/16 as compared to 2014/15.

RATIONALE FOR QUESTION:

To better understand both historic and forecast extra-provincial revenues in the Application.

RESPONSE:

IESO market rules continue to evolve. In 2014 the IESO revised their interpretation of the market rule associated with the calculation of its day ahead price guarantee (DA-IOG) and applied the revised interpretation retroactively to 2012 at a cost to Manitoba Hydro of $8.8 million. Manitoba Hydro's estimate of IESO revenues for 2014/15 and 2015/16 reflect this cost and the new market rule interpretation and expected level of market activity and arbitrage opportunities.

Section:	5	**Page No.:**	16
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Treatment of Subsidiaries		

PREAMBLE TO IR (IF ANY):

QUESTION:

It is noted that, unlike Appendix 5.6 from the previous GRA, there is no separate identification in the current Schedule 5.1.4 of OM&A associated with subsidiaries. Please clarify if subsidiary OM&A is included in Schedule 5.1.4 and, if so indicate what the values are for each year.

RATIONALE FOR QUESTION:

Clarify the basis for the OM&A expenses shown.

RESPONSE:

Please see the response to COALITION/MH-I-21b.

Section:	5	**Page No.:**	16
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Treatment of Subsidiaries		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the OM&A values include subsidiary OM&A, please reconcile this with the fact that there is no offsetting subsidiary revenue included in Other Revenues (per Page 13).

RATIONALE FOR QUESTION:

Clarify the basis for the OM&A expenses shown.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH I-21b.

Section:	5	**Page No.:**	16
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Strategic Initiatives and Contingency Funding		

PREAMBLE TO IR (IF ANY):

QUESTION:

The current IFF14 includes roughly $2.6 M in contingency funding for each of the years 2014/15 through 2016/17. What are these funds meant to address and how was the level of funding established.

RATIONALE FOR QUESTION:

Clarify the OM&A Expenses shown for 2014/15 through 2016/17.

RESPONSE:

The contingency forecast is a corporate provision for unforeseen events or circumstances in day to day operations which cannot easily be absorbed by advancing or deferring the timing of essential operational expenditures. The level of contingency funding allows the Corporation to balance these requirements while maintaining OM&A expenditures below inflationary levels and is calculated as the difference between the detailed departmental budgets and the overall OM&A target. The funding of approximately $2.6 million is representative of the historical average contingency forecast.

Section:	5	**Page No.:**	16
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Strategic Initiatives and Contingency Funding		

PREAMBLE TO IR (IF ANY):

QUESTION:

The current IFF14 includes funds for a Strategic Funding Initiative that increase to $6.3 M in 2016/17. What is the purpose of these funds and how was the level of funding established?

RATIONALE FOR QUESTION:

Clarify the OM&A Expenses shown for 2014/15 through 2016/17.

RESPONSE:

The Strategic Initiative Fund was established as part of the operating budget process during IFF14 and is a corporate provision for strategic programs outside of regular business unit operations that support the Corporation's priorities. For example, in support of Manitoba Hydro's commitment to reduce costs, funding was required for the Supply Chain Management Initiative which is intended to realize savings over the long term in procurement, inventory management, material distribution and fleet operations.

The established level of funding allows the Corporation to balance these requirements with its efforts to implement aggressive cost containment measures in order to limit OM&A expenditures to a 1% inflationary increase.

Section:	Tab 5: Appendix 5.5, Figures 5.5.5, 5.5.13 & 5.5.16 Tab 5: Appendix 5.1	Page No.:	6, 15 & 21 104
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Reconciliation of Actual Results with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please revise Figure 5.5.13 to include actuals for 2011/12 using the same format.

RATIONALE FOR QUESTION:

To understand changes as between previous forecasts and the actual results reported up to 2013/14. Does not duplicate questions PUB/MH 1-26 through 1-36.

RESPONSE:

Please see the response to PUB/MH-I-73b, which provides OM&A by cost element from 2008/09 to 2016/17.

Section:	Tab 5: Appendix 5.5, Figures 5.5.5, 5.5.13 & 5.5.16 Tab 5: Appendix 5.1	**Page No.:**	6, 15 & 21 104
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Reconciliation of Actual Results with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the value for 2011/12 Electric Operations shown in response to part a) for 2011/12 does not match that reported in Appendix 5.6, page 7 from the previous GRA, please provide a reconciliation.

RATIONALE FOR QUESTION:

To understand changes as between previous forecasts and the actual results reported up to 2013/14. Does not duplicate questions PUB/MH 1-26 through 1-36.

RESPONSE:

Please see the following reconciliation of the 2011/12 actuals from Appendix 5.6 from the previous GRA to the response provided in PUB/MH-I-73b.

	2011/12 Actuals
Appendix 5.6 - 2012 GRA: OM&A Attributable to Electric Operations per Annual Report (Inclucing Subsidiaries)	410 717
Less Subsidiaries	7 414
Electric Only OM&A	403 303
Add Operating Expense Recovery Reclassifications*	8 732
PUB-MH I-73b: Electric OM&A, including Accounting Changes	412 035

* The reclassification of operating expense recoveries to other revenue was made in 2012/13 and applied retroactively to 2011/12.

Section:	Tab 5: Appendix 5.5, Figures 5.5.5, 5.5.13 & 5.5.16 Tab 5: Appendix 5.1	Page No.:	6, 15 & 21 104
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Reconciliation of Actual Results with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain the variance between the forecast accounting change impacts for 2012/13 and 2013/14 (per Appendix 5.6, page 5 from the last GRA) with the actual impacts reported in Appendix 5.5, Figure 5.5.5.

RATIONALE FOR QUESTION:

To understand changes as between previous forecasts and the actual results reported up to 2013/14. Does not duplicate questions PUB/MH 1-26 through 1-36.

RESPONSE:

The variance between the forecast accounting change impacts for 2012/13 and 2013/14 as per Appendix 5.6, page 5 from the last GRA as compared to the actual impacts reported in Appendix 5.5, Figure 5.5.5 are shown in the table below.

SUMMARY OF ACCOUNTING & BENEFIT CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	Figure 5.5.5 2015 GRA		Appendix 5.6 2012 GRA			
	2012/13 Actual	2013/14 Actual	2012/13 Forecast	2013/14 Forecast	2012/13 Variance	2013/14 Variance
PP&E Reduction to Costs Capitalized	$ 60,180	$ 61,384	$ 56,488	$ 57,617	$ 3,692	$ 3,766
Intangible Assets	4,330	4,416	4,330	4,416	-	-
Pension & Benefits	13,835	25,355	8,352	9,918	5,483	15,437
Total OM&A Impact	$ 78,345	$ 91,155	$ 69,169	$ 71,952	$ 9,176	$ 19,204

The increase in PP&E Reduction to Costs Capitalized for both 2012/13 and 2013/14 is primarily a result of higher levels of construction activity, resulting in a proportionate increased allocation of overhead to capital.

The increase in Pension & Benefits is primarily due to the 2012 GRA forecast figures including only the accounting change impacts for current and past service pension costs, whereas the actual results include changes for all benefit costs and reflect the impacts of a lower discount rate, higher employee levels and increases in wages & salaries as a result of contract settlements.

Section:	Tab 5: Appendix 5.5, Figures 5.5.5, 5.5.13 & 5.5.16 Tab 5: Appendix 5.1	**Page No.:**	6, 15 & 21 104
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Reconciliation of Actual Results with Previous Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please reconcile the actual electric operations OM&A reported in Appendix 5.5, page 15 for 2012/13 and 2013/14 with that shown in Appendix 5.1, page 104.

RATIONALE FOR QUESTION:

To understand changes as between previous forecasts and the actual results reported up to 2013/14. Does not duplicate questions PUB/MH 1-26 through 1-36.

RESPONSE:

Please see the response to COALITION/MH-I-39c.

Section:	Tab 5: Appendix 5.5, Figures 5.5.13 & 5.5.16	**Page No.:**	15 & 21
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	OM&A Reconciliation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please reconcile the total OM&A values reported in Figure 5.5.16 with the OM&A values reported in 5.5.13 for each of the years shown. For example, please reconcile the $609.6 M value for 2012/13 in the former with the $596.4 M value in the latter.

RATIONALE FOR QUESTION:

Information request seeks to reconcile the Electric OM&A values reported in the Application.

RESPONSE:

The OM&A values in Figure 5.5.16 include Business Unit OM&A costs only. The schedule below reconciles Figure 5.5.16 to Figure 5.5.13 OM&A by Cost Element.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/Dec
President & CEO	$ 12,648	$ 10,887	$ 12,309	$ 12,469	$ 12,460	0.1%
General Counsel & Corporate Secretary	8,741	9,316	9,244	9,222	9,232	1.4%
Human Resources & Corporate Services	94,161	106,036	108,058	108,161	107,814	3.6%
Corporate Relations	9,730	8,918	10,059	10,008	10,033	1.0%
Finance & Regulatory	17,480	18,510	20,033	20,104	20,182	3.7%
Generation Operations	125,533	135,373	138,290	141,178	142,959	3.3%
Major Capital Projects	2,912	4,384	5,638	4,568	4,588	15.1%
Transmission	156,442	163,910	164,112	165,338	165,995	1.5%
Customer Service & Distribution	132,330	130,902	134,922	132,275	133,490	0.2%
Customer Care & Energy Conservation	49,624	55,353	58,361	56,364	56,837	3.6%
Business Unit	**609,602**	**643,590**	**661,027**	**659,687**	**663,591**	**2.2%**
Corporate Allocations & Adjustments	(13,196)	(21,617)	(26,177)	(26,678)	(19,274)	14.8%
Total	**596,406**	**621,973**	**634,849**	**633,009**	**644,317**	**2.0%**
Less:						
Capitalized Overhead	(69,720)	(74,446)	(81,265)	(24,578)	(24,824)	-13.2%
Operating and Administration Charged to Centra	(63,735)	(66,810)	(67,829)	(66,691)	(67,818)	1.6%
Electric OM&A, including Accounting Changes	**462,952**	**480,717**	**485,755**	**541,740**	**551,675**	**4.6%**
Less: Acounting Changes	(78,345)	(91,155)	(93,858)	(145,644)	(151,345)	
Electric OM&A, excluding Accounting Changes	**$ 384,607**	**$ 389,562**	**$ 391,897**	**$ 396,096**	**$ 400,330**	**1.0%**

Section:	Tab 5: Appendix 5.5, Figures 5.5.13 & 5.5.16	**Page No.:**	15 & 21
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	OM&A Reconciliation		

PREAMBLE TO IR (IF ANY):

QUESTION:

For each of the Business Unit reported in Schedule 5.5.16, please provide a schedule that sets out the adjustments (e.g., accounting changes, charges to capital, capitalized overhead and charges to Centra) required to arrive at the Unit's contribution to Electric OM&A (excluding accounting changes) per Schedule 5.5.13 for each year shown.

RATIONALE FOR QUESTION:

Information request seeks to reconcile the Electric OM&A values reported in the Application.

RESPONSE:

Schedule 5.5.16 includes all costs attributable to Business Unit OM&A. Activity charges to capital projects are imbedded within Business Unit OM&A and are a direct reduction of business unit costs.

The following table details the reductions to Business Unit OM&A as a result of activity charges to capital for the years 2012/13 to 2016/17.

MANITOBA HYDRO
COSTS CAPITALIZED BY BUSINESS UNIT

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO	$ (275)	$ (53)	$ -	$ -	$ -
General Counsel & Corporate Secretary	(639)	(1,299)	(905)	(922)	(948)
Human Resources & Corporate Services	(13,062)	(13,564)	(16,580)	(16,115)	(16,256)
Corporate Relations	(4,233)	(4,118)	(4,757)	(4,847)	(4,992)
Finance & Regulatory	(273)	(940)	(399)	(271)	(274)
Generation Operations	(34,670)	(40,289)	(41,561)	(40,345)	(41,125)
Major Capital Projects	(24,593)	(28,451)	(33,977)	(48,711)	(49,562)
Transmission	(73,232)	(79,235)	(88,013)	(94,171)	(95,863)
Customer Service & Distribution	(84,835)	(88,319)	(92,588)	(97,926)	(99,955)
Customer Care & Energy Conservation	(9,007)	(9,746)	(11,135)	(13,673)	(13,812)
Total Costs Capitalized	**$ (244,819)**	**$ (266,013)**	**$ (289,917)**	**$ (316,982)**	**$ (322,787)**

Capitalized Overhead, Operating and Administration Charged to Centra and Accounting Changes are captured at the company level and are not tracked or recorded by business unit.

Overhead costs, such as corporate services and departmental support functions, are pooled and allocated as a percentage add-on to activity charges. The capitalized overhead allocation is proportionate to the activity charged to capital projects and is not specific to the business unit from which the costs originated.

Operating and Administration Charged to Centra represents costs associated with providing resources required for the operations and maintenance activities of Centra Gas. These costs are pooled and charged to Centra based upon various cost drivers (e.g. activity charges, number of customers, etc.) according to the nature of the costs. The allocation is not specific to the business unit from which the costs originated.

The accounting changes impacting OM&A are primarily the result of a reduction in the amount of overhead capitalized as well as increases in pension and benefit costs as a result of changes in the discount rate and the impacts of transitioning to IFRS in 2015/16. As previously discussed, these costs are not tracked or recorded by individual business unit.

Section:	Tab 5, Appendix 5.5, Figures 5.5.13 and 5.5.16 Tab 11: Appendix 11.30	Page No.:	
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Detailed Forecast versus Actual Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm the basis of the forecast OM&A values for 2012/13 and 2013/14 used in Appendix 11.30 (i.e., from which IFF).

RATIONALE FOR QUESTION:

Compare the actual OM&A expenses reported for 2012/13 & 2013/14 with forecast values that were reviewed and tested in the previous GRA.

RESPONSE:

Manitoba Hydro confirms that as indicated in Appendix 11.30, the forecast values are from IFF12.

Section:	Tab 5, Appendix 5.5, Figures 5.5.13 and 5.5.16 Tab 11: Appendix 11.30	Page No.:	
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Detailed Forecast versus Actual Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

Were the forecast values for the level of detail used in Appendix 11.30 actually filed in the last GRA? If so, please provide the reference.

RATIONALE FOR QUESTION:

Compare the actual OM&A expenses reported for 2012/13 & 2013/14 with forecast values that were reviewed and tested in the previous GRA.

RESPONSE:

The IFF12 forecast information was filed in MIPUG-Pre-ask 12.

Please note, Appendix 11.30 restates the forecasted costs between employee benefits and capitalized overhead for 2012/13 and 2013/14 as compared to MIPUG-Pre-ask 12. However, there was no impact to total OM&A costs.

Section:	Tab 5, Appendix 5.5, Figures 5.5.13 and 5.5.16 Tab 11: Appendix 11.30	Page No.:	
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Detailed Forecast versus Actual Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

If the detailed forecast values were not presented in the last GRA, please provide schedules that compare the forecast OM&A as filed in the previous GRA (Appendix 5.6) for 2012/13 and 2013/14 with the actual results reported in the current Application on the basis of i) cost element and ii) business unit. Please explain any variances of more than 5%.

RATIONALE FOR QUESTION:

Compare the actual OM&A expenses reported for 2012/13 & 2013/14 with forecast values that were reviewed and tested in the previous GRA.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-46b and Appendix 11.30.

Section:	Tab 5: Appendix 5.5, Figures 5.5.8 & 5.5.10 2012/13 & 2013/14 GRA, Appendix 5.6	Page No.:	10 & 12 12
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Detailed ETF Forecast versus Actuals		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that compares the forecast ETFs by Business Unit as filed in the previous GRA for 2012/13 and 2013/14 (Appendix 5.6) with the actual ETFs reported in the current Application. Please explain any variances of more than 5%.

RATIONALE FOR QUESTION:

Compare the actual ETFs by Business Unit reported for 2012/13 & 2013/14 with the forecast values that were reviewed and tested in the previous GRA. It is distinct from PUB/MH 1-30 to 1-32.

RESPONSE:

Total EFTs (straight time and overtime) are lower than forecast by 164 in 2012/13 and 86 in 2013/14 primarily as a result of Manitoba Hydro's continuing efforts to control costs. The attached table provides a comparison of total EFTs to forecast by business unit.

Variances greater than 5% and 5 EFTs have been explained.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2012/13 Actual	2012/13 Forecast	Increase/ (Decrease)	%	Notes	2013/14 Actual	2013/14 Forecast	2013/14 Variance	Increase/ (Decrease)	Notes
President & CEO	50	52	(1)	-3%		43	52	(9)	-17%	2
General Counsel & Corporate Secretary	39	41	(1)	-4%		44	41	3	8%	
Human Resources & Corporate Services	822	847	(24)	-3%		828	847	(19)	-2%	
Corporate Relations	89	94	(4)	-5%		86	94	(8)	-8%	3
Finance & Regulatory	149	147	1	1%		151	147	3	2%	
Generation Operations	1,163	1,200	(37)	-3%		1,196	1,200	(4)	0%	
Major Capital Projects	225	252	(27)	-11%	1	257	252	4	2%	
Transmission	1,876	1,905	(29)	-2%		1,904	1,905	(1)	0%	
Customer Service & Distribution	1,760	1,776	(16)	-1%		1,737	1,776	(39)	-2%	
Customer Care & Energy Conservation	503	528	(25)	-5%		510	528	(17)	-3%	
Total	**6,678**	**6,842**	**(164)**	**-2%**		**6,756**	**6,842**	**(86)**	**-1%**	

1) Major Capital Projects – Lower EFTs primarily due to vacant positions not yet filled for projects such as Keeyask Generating Station, Bipole III Converter Stations and Conawapa Generating Station.

2) President & CEO – Lower EFTs due to staff transfers to Human Resources & Corporate Services, General Counsel & Corporate Secretary and Corporate Relations.

3) Corporate Relations – Lower EFTs as a result of cost containment reductions primarily in support functions, partially offset by staff transfers from President & CEO.

Section:	Tab 5: Appendix 5.5 Tab 11: Appendix 11.25	Page No.:	4 2
Topic:	Financial Results & Forecasts		
Subtopic:	Operating, Maintenance and Administrative		
Issue:	Increases in Average Salary/ETF		

PREAMBLE TO IR (IF ANY):

Appendix 5.5 (page 4) states that overall wage increases are 3%-4% per annum.

QUESTION:

Please identity those Divisions where the average salary per EFT increases by more than 4%/annum over the period 2013/14 to 2016/17. For each such Business Unit, please provide an explanation as to why this is the case.

RATIONALE FOR QUESTION:

To understand the reasons for average salary per ETF increases greater then the Corporate norm.

RESPONSE:

The table below provides the average annual increase in the average salary per EFT by Business Unit.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY BUSINESS UNIT

	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual Increase
President & CEO	$ 111,813	$ 125,551	$ 130,486	$ 136,832	7%
General Counsel & Corporate Secretary	98,168	99,831	103,648	107,519	3%
Human Resources & Corporate Services	76,494	77,821	81,325	83,566	3%
Corporate Relations	77,631	80,351	83,756	86,462	4%
Finance & Regulatory	84,740	88,040	92,309	94,532	4%
Generation Operations	80,225	82,803	86,391	88,512	3%
Major Capital Projects	81,845	84,562	85,293	88,000	3%
Transmission	75,710	77,961	82,006	85,110	4%
Customer Services & Distribution	67,499	69,994	72,886	75,381	4%
Customer Care & Energy Conservation	69,291	71,681	74,608	76,461	3%
Business Unit Total	**$ 74,791**	**$ 77,168**	**$ 80,585**	**$ 83,129**	**4%**

The President & CEO business unit is relatively small and includes a large component of executives, affecting the average salary differently than other areas of the corporation because of the design of their performance based salary administration program. Manitoba Hydro is embarking on a decade of unprecedented change and financial investment in new generation capacity and infrastructure. The ability to attract and retain key talent in a highly specialized industry that is facing increased competition for resources is integral to the success of the Corporation in managing this change. As such, the Manitoba Hydro Electric Board approved performance based, salary market adjustments for Manitoba Hydro's executives in order to improve its competitive executive compensation positioning among large Manitoba companies and utilities across the country.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	**Page No.:**	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Manitoba Hydro is planning (Tab 5, page 26) on eliminating the provision in depreciation rates for asset removal costs upon its transition to IRFS. How will asset removal costs be recovered upon elimination of the provision and where/how does this impact IFF14?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Upon the adoption of IFRS by Manitoba Hydro, asset removal costs will be recovered by either the recognition of an asset retirement obligation or by adding the removal costs of the retired asset to the cost of the replacement asset.

- Asset retirement obligations will be recognized where Manitoba Hydro has a future obligation to terminally retire a significant plant asset and the costs associated with retiring that asset are material and can be reasonably estimated. In the year that the decision is made to retire the asset, Manitoba Hydro will record the present value of the future costs to retire the asset as an additional cost of the asset to be retired. These costs will be amortized over the remaining service life of the asset. In addition, as the present value cost of the obligation increases each year towards the asset's retirement date, an annual accretion charge will be made to finance expense.

As of March 31, 2014, Manitoba Hydro has asset retirement costs established for the future decommissioning of the Brandon Thermal Generating Station and for the partial decommissioning of the Pointe du Bois Generating Station spillway.

- In circumstances where the plant asset to be retired is to be replaced by a similar plant asset, the costs of removing the retired asset will be added to the cost of the replacement asset and amortized over the service life of the asset.

IFF14 assumes no new asset retirement obligations and that asset removal costs are added to the cost of the replacement asset and amortized over the service life of the asset. In addition, IFF14 assumes an adjustment to retained earnings of $57 million for retrospective application of the negative salvage costs for fiscal 2014/15.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	**Page No.:**	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the $2 M reduction in depreciation shown for 2016/17 and attributed to Overhead Ineligible for Capitalization (per Appendix 5.6, page 2) reflects the lower capital costs for facilities coming into service in 2016/17 due to the adoption of IFRS in 2015/16 and the corresponding reduction in capitalized OM&A costs for these projects.

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Confirmed. The $2 million reduction in depreciation expense for the 2016/17 forecast year is attributed to lower capital costs for facilities coming into service as a result of expensing overhead costs ineligible for capitalization in both the 2015/16 and 2016/17 forecast years. Such costs are being expensed as a result of the adoption of IFRS in fiscal 2015/16.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	**Page No.:**	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please clarify whether the 2015 Approved ASL Rates in Appendix 5.6, page 7 are viewed as IFRS compliant – per Tab 11, page 14. If not, why not?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Please see the response to PUB MH-I-39c.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	Page No.:	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Has Manitoba Hydro recently reviewed the 10 year amortization rate adopted for DSM as of 2008/09 (per Appendix 11.43)? If yes, please provide the results. If not, why not?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

The 10 year amortization period (previously 15 years) was adopted in 2008/09 on the recommendation of the PUB in Order 116/08 to shorten the period to be consistent with industry practices. Based on Manitoba Hydro's review of similar programs offered within the industry, the 10 year amortization period falls within the range of amortization periods used by other Canadian utilities.

Section:	Tab 5: Appendix 5.7	**Page No.:**	2
Topic:	Financial Results & Forecasts		
Subtopic:	Accounting Policy & Estimate Changes		
Issue:	Reclassification of Unamortized Experience Gains and Losses on Pension Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the reclassification of unamortized experience gains and losses on pension balances (page 2), does this have any impact on either the Operating Statement or the calculation of Manitoba Hydro's Debt/Equity ratio? If so, please explain how.

RATIONALE FOR QUESTION:

Clarify the impact on Manitoba Hydro's financial results of the reclassification of unamortized experience gains and losses on pension balances.

RESPONSE:

The reclassification of unamortized experience gains and losses on pension balances will impact both the Operating Statement and the calculation of Manitoba Hydro's debt:equity ratio.

Under CGAAP, Manitoba Hydro used the corridor method of amortization for actuarial gains and losses related to the pension plans. The amortization of these gains and losses was recognized in pension expense on an annual basis when the cumulative unamortized net gain or loss exceeded 10% of the greater of the accrued benefit obligation or the market value of the plan assets at the beginning of the year. This excess was amortized to operating expense over the estimated remaining service life of employees covered by the plan.

The corridor accounting methodology has been eliminated under IFRS. As a result, there will be no amortization of corridor included in operating expenses. Unamortized experience gains and losses on pension balances will be reclassified to Accumulated Other Comprehensive Income (AOCI) on transition to IFRS.

It should be noted that the reduction in corridor amortization is offset by an increase in pension expense resulting from the change in the interest rate used to calculate the expected return on fund assets.

AOCI is considered a component of equity for the calculation of the debt:equity ratio. The reclassification of unamortized net losses to AOCI upon transition will reduce the equity component and increase the debt component of the debt:equity ratio.

Section:	Tab 5: Appendix 5.7 Tab 10	Page No.:	4 3
Topic:	Financial Results & Forecasts		
Subtopic:	Accounting Policy & Estimate Changes		
Issue:	Impact of IFRS		

PREAMBLE TO IR (IF ANY):

QUESTION:

Tab 10 characterizes all of the accounting policy and estimate changes discussed in Appendix 5.7 as IFRS driven. Please comment on whether this is truly the case and, in particular, whether the average service life changes (based on the 2014 Depreciation Study) are the result of moving to IFRS or would be adopted in any event.

RATIONALE FOR QUESTION:

To better understand the changes driven by IFRS.

RESPONSE:

Manitoba Hydro disagrees that Tab 10 characterizes all of the accounting policy and estimate changes discussed in Appendix 5.7 as IFRS driven. As stated on page 3 of Tab 10,

> *"As outlined in Appendix 5.7 of Tab 5, the overall impacts of the accounting policy and estimate changes that are forecast to be made in 2014/15 and 2015/16 offset each other and result in an overall reduction in Manitoba Hydro's future revenue requirements, and as such are not driving the need for the proposed rate increases."*

The term "overall impacts" is referring to both the IFRS and non-IFRS accounting policy changes and are discussed separately in Appendix 5.7. Section 2.0 of Appendix 5.7 discusses the impacts of the 2014 depreciation study, which developed new depreciation rates as a result of changes in service lives. These changes would be adopted regardless of whether or not Manitoba Hydro was transitioning to IFRS. The impacts of the transition to IFRS are discussed in Section 3.0.

As discussed in Tab 10, the net impact of the accounting changes offset each other resulting in an overall reduction in future revenue requirements. The accounting changes are not driving the need for rate increases such that the changes should be adopted collectively, so as to avoid the issues around maintaining two different sets of financial records.

Section:	Tab 5	**Page No.:**	37
Topic:	Financial Results & Forecasts		
Subtopic:	Capital Taxes		
Issue:	Effect of Capital Contributions		

PREAMBLE TO IR (IF ANY):

QUESTION:

Does Manitoba Hydro pay capital tax on capital contributions received from customers and other parties (e.g., capital contributed by AANDC for Diesel Communities)?

RATIONALE FOR QUESTION:

To clarify the treatment of capital contributions in the calculation of capital taxes.

RESPONSE:

Manitoba Hydro does not pay capital tax on capital contributions received from customers and others.

Section:	Tab 6 Tab 6: Appendix 6.13	Page No.:	6 3
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area & Roadway Lighting		
Issue:	New LED Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Was PCOSS13 the most current Prospective Cost of Service Study (PCOSS) available at the time the rates were being established (i.e. June 2014)?

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize the interim ARL LED rates and also set new rates for the forward test period.

RESPONSE:

Yes. PCOSS13 was the most current study available when LED rates were prepared as part of the Application for Interim Electric Rates effective April 1, 2014.

Section:	Tab 6 Tab 6: Appendix 6.13	**Page No.:**	6 3
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area & Roadway Lighting		
Issue:	New LED Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

If not, what was the most recent PCOSS available at the time and what was the energy cost per kWh from that study? Note: Please provide a copy of the Customer, Demand and Energy Cost Analysis from the study.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize the interim ARL LED rates and also set new rates for the forward test period.

RESPONSE:

The energy cost 4.85¢/kWh is provided in the attached PCOSS13 Customer, Demand and Energy Schedule.

SCHEDULE B5

Customer, Demand, Energy Cost Analysis – With Methodology Changes

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2013
Customer, Demand, Energy Cost Analysis

SUMMARY

	CUSTOMER			DEMAND				ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	114,272	480,996	19.80	201,851	0%	n/a	n/a	242,702	7,266,318	6.12	**
GS Small - Non Demand	23,051	53,714	35.76	39,309	0%	n/a	n/a	57,703	1,612,575	6.02	**
GS Small - Demand	8,081	12,297	54.76	43,124	37%	2,195	7.22	68,585	1,971,347	4.86	
General Service - Medium	6,824	1,938	293.42	62,650	87%	7,026	7.75	104,719	3,100,595	3.64	
General Service - Large <30kV	3,494	289	n/a	28,167	100%	4,148	7.63 *	56,967	1,721,592	3.31	
General Service - Large 30-100kV	2,440	40	n/a	9,893	100%	2,121	5.81 *	31,840	1,053,524	3.02	
General Service - Large >100kV	2,163	16	n/a	30,172	100%	8,511	3.80 *	146,648	4,857,207	3.02	
SEP	287	26	918.91	155	0%	n/a	n/a	562	25,600	2.80	**
Area & Roadway Lighting	15,408	153,444	8.37	2,237	0%	n/a	n/a	2,613	100,062	4.85	**
Total General Consumers	176,019	702,760		417,559		24,001		712,339	21,708,820		
Diesel	235	737	26.53	352	0%	n/a	n/a	8,432	13,463	65.25	**
Export	n/a	n/a	n/a	27,851	0%	n/a	n/a	250,021	7,340,000	3.79	***
Total System	176,254	703,497		445,762		24,001		970,793	29,062,282		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Section:	Tab 6 Tab 6: Appendix 6.13	Page No.:	6 3
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area & Roadway Lighting		
Issue:	New LED Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a copy of the Customer, Demand and Energy Cost Analysis from the most current PCOSS available.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize the interim ARL LED rates and also set new rates for the forward test period.

RESPONSE:

The energy unit cost for Area and Roadway Lighting from PCOSS14 is 5.05¢/kWh, as shown in the attached schedule of Customer, Demand and Energy costs. PCOSS14 included revenues based on May 1, 2013 rates. After adjusting revenues to reflect the interim May 1, 2014 and the proposed April 1, 2015 rate increases, an energy rate of 5.39¢/kWh results.

SCHEDULE B2
Customer, Demand, Energy Cost Analysis

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Customer, Demand, Energy Cost Analysis

SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy mWh	ENERGY Unit Cost ¢/kWh
Residential	125,710	486,987	21.51	206,996	0%	n/a	n/a	264,371	7,404,453	6.37 **
GS Small - Non Demand	25,036	53,778	38.80	39,575	0%	n/a	n/a	60,544	1,605,511	6.24 **
GS Small - Demand	8,507	12,492	56.75	45,970	38%	2,390	7.29	75,032	2,047,715	5.06
General Service - Medium	7,439	1,974	314.05	66,170	87%	7,302	7.92	113,197	3,174,662	3.83
General Service - Large <30kV	3,742	288	n/a	29,255	100%	4,042	8.16 *	59,629	1,702,481	3.50
General Service - Large 30-100kV	2,587	40	n/a	11,951	100%	2,894	5.02 *	42,279	1,327,210	3.19
General Service - Large >100kV	2,390	16	n/a	29,475	100%	8,409	3.79 *	155,406	4,903,742	3.17
SEP	326	29	935.95	132	0%	n/a	n/a	509	26,500	2.42 **
Area & Roadway Lighting	16,622	155,024	8.94	2,329	0%	n/a	n/a	2,749	100,487	5.05 **
Total General Consumers	192,358	710,628		431,853		25,038		773,717	22,292,761	
Diesel	229	755	25.27	343	0%	n/a	n/a	9,130	13,754	68.88 **
Export	n/a	n/a	n/a	31,054	0%	n/a	n/a	279,802	9,013,000	3.45 ***
Total System	192,587	711,383		463,251		25,038		1,062,649	31,319,515	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Section:	Tab 6 Tab 6: Appendix 6.13	Page No.:	6 3
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area & Roadway Lighting		
Issue:	New LED Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

How does Manitoba Hydro determine what type of lighting is being used by a municipality and therefore which Outdoor Lighting Rate is applicable (e.g. does it perform its own audit, require a 3rd party audit or rely on information provide by the municipalities)?

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize the interim ARL LED rates and also set new rates for the forward test period.

RESPONSE:

Lighting billed under the Area & Roadway Lighting is owned by Manitoba Hydro. Cities, towns and municipalities contract with Manitoba Hydro for the provision, installation and maintenance of the lighting. Additions and removals of lighting are tracked internally through process forms specifically detailing the lighting (type and wattage) and pole type to identify the corresponding classes of Area & Roadway Lighting and entered into Manitoba Hydro's billing system.

As Manitoba Hydro moves forward with the mass conversions under the LED Roadway Lighting Conversion Program and new roadway lighting installations, LED fixtures will be electronically inventoried. This information will serve as a reference for billing purposes.

Section:	Tab 6	**Page No.:**	3
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Proof of Revenue		
Issue:	Proof of Revenue Analysis for 2014/15		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a detailed proof of revenue analysis for the rates requested for 2014/15 that sets out the actual calculations for each rate class. As part of the analysis please show the billing determinants forecast for each customer class for 2014/15.

RATIONALE FOR QUESTION:

No proof of revenue analysis has been provided for the 2014/15 rates for which Manitoba Hydro is seeking final approval.

RESPONSE:

Please see Manitoba Hydro's response to MIPUG/MH-I 4b.

Section:	Tab 6 Tab 6: Appendix 6.8	Page No.:	13 6
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Surplus Energy Program		
Issue:	Proposed Changes to Option 1		

PREAMBLE TO IR (IF ANY):

It is noted (Appendix 6.8) that as of October 31, 2014 there are still no customers on SEP Option #1.

QUESTION:

Have any customers expressed an interest in SEP-Option 1 since Order 43/13 was issued?

RATIONALE FOR QUESTION:

Confirm the need for the changes proposed to SEP – Option #1.

RESPONSE:

To date, no customers have expressed interest in the SEP – Option 1 since Order 43/13 was issued.

Section:	Tab 6 Tab 6: Appendix 6.8	**Page No.:**	13 6
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Surplus Energy Program		
Issue:	Proposed Changes to Option 1		

PREAMBLE TO IR (IF ANY):

It is noted (Appendix 6.8) that as of October 31, 2014 there are still no customers on SEP Option #1.

QUESTION:

If yes, were the proposed changes to Option 1 a factor in their expression of interest?

RATIONALE FOR QUESTION:

Confirm the need for the changes proposed to SEP – Option #1.

RESPONSE:

Please refer to the response in COALITION/MH-I-55a.

Section:	Tab 6 Tab 6: Appendix 6.8	**Page No.:**	13 6
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Surplus Energy Program		
Issue:	Proposed Changes to Option 1		

PREAMBLE TO IR (IF ANY):

It is noted (Appendix 6.8) that as of October 31, 2014 there are still no customers on SEP Option #1.

QUESTION:

Based on the responses to parts (a) and (b), does Manitoba Hydro still see a benefit in the proposed SEP changes? If so, why?

RATIONALE FOR QUESTION:

Confirm the need for the changes proposed to SEP – Option #1.

RESPONSE:

The SEP – Option 1 rate option is made available to larger customers (total load of 1.0 MVA or greater) who may have an opportunity to utilize a non-firm energy supply based on pricing that reflects Manitoba Hydro's opportunity cost for surplus energy. As such, the option would provide value to the customer. The option is not intended as a replacement for firm energy supply and is therefore not viewed as competition for energy served under firm rates.

Section:	Tab 6 Tab 6: Appendix 6.10	Page No.:	14 5
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Change in Peak and Off-Peak Definitions		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm what the current Peak and Off-Peak period definitions are as used for the CRP.

RATIONALE FOR QUESTION:

Clarify what the change in definition of peak and off-peak is and the basis for the change.

RESPONSE:

The current Peak and Off-Peak periods for the CRP are defined as follows:

Peak: 7:01 to 23:00 Monday to Sunday inclusive
Off-Peak: 23:01 to 7:00 Monday to Sunday inclusive

Manitoba Hydro is proposing to modify the Peak and Off-Peak periods for the CRP to be defined as follows:

Peak: 6:01 to 22:00 Monday to Friday inclusive excluding Statutory holidays
Off-Peak: 22:01 to 06:00 Monday to Friday inclusive, and all hours from 0:01 to 24:00 on Saturday, Sunday and Statutory holidays.

These proposed periods are intended to conform with the periods for On-Peak (5 days X 16 hours) and Off-Peak hours (the balance of all remaining hours) as defined in the MISO market (balance of hours).

Manitoba Hydro is also proposing to structure its Time-of-Use Rate for GSL > 30 kV customers in the same manner, to ensure that these rate designs are reflective and consistent with the time periods experienced in the MISO market.

Section:	Tab 6 Tab 6: Appendix 6.10	**Page No.:**	14 5
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Change in Peak and Off-Peak Definitions		

PREAMBLE TO IR (IF ANY):

QUESTION:

Do the proposed Peak and Off-Peak periods for the CRP match the definition of peak and off-peak as used in the MISO market (per Tab 9, page 10)?

RATIONALE FOR QUESTION:

Clarify what the change in definition of peak and off-peak is and the basis for the change.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-56a.

Section:	Tab 6 Tab 6: Appendix 6.10	Page No.:	14 5
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Change in Peak and Off-Peak Definitions		

PREAMBLE TO IR (IF ANY):

QUESTION:

If not, please explain how the new definitions of peak and off-peak were determined. Note: If the only rationale is to align the definitions with those used for the proposed industrial TOU rates – please provide the rationale for the TOU peak and off-peak rate periods.

RATIONALE FOR QUESTION:

Clarify what the change in definition of peak and off-peak is and the basis for the change.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-56a.

Section:	Tab 6	**Page No.:**	14
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Proposed Elimination of Option C		

PREAMBLE TO IR (IF ANY):

QUESTION:

Has the customer on Option C indicated yet whether it will be converting to Option A or to Firm Load?

RATIONALE FOR QUESTION:

To clarify the likely treatment of the current Option C customer.

RESPONSE:

Based on most recent inquires, the customer on Option C has not provided an indication as to whether their Option C curtailable load will be converted to either Option A curtailable load or Firm Load.

Section:	Tab 6 Tab 6: Appendix 6.10	Page No.:	14 13
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Conditions for Returning to CRP		

PREAMBLE TO IR (IF ANY):

Tab 6, page 14 states that the amended conditions allow customers to go back on CRP, if they have switched their curtailable load to firm, provided one year has passed since they went off the program. Appendix 6.10 states that customers may re-designate their Protected Firm Load or Guaranteed Interruptible Load by providing 12 months written notice.

QUESTION:

Please clarify the amended terms. Must the customer wait 12 months before providing the 12 months written notice or is the 12 month period referred to in Tab 6 the same 12 months as referred to in Appendix 6.10?

RATIONALE FOR QUESTION:

To clarify the proposed conditions under which a customer may switch back to CRP.

RESPONSE:

The twelve month periods referenced in the “Preamble to IR” above are two distinct situations in the CRP Terms and Conditions.

The 12 month reference noted in Tab 6, page 14 relates to Appendix 6.10, section 7 (iv) c) on page 12 of the proposed CRP Terms and Conditions. Manitoba Hydro is proposing to allow customers who had been on CRP in excess of six months and then switched to firm service, to go back on CRP provided 12 months has passed since they went off CRP. For example, if a CRP customer decided to switch off CRP and go onto firm service effective to March 1, 2014, they could not go back on CRP until March 1, 2015 at the earliest, assuming curtailable load is available as defined in Section 6 of the CRP terms and conditions.

The 12 month reference noted in Appendix 6.10, section 7 (v) on page 13 of the CRP Terms and Conditions, allows customers who are currently on CRP to re-designate their Protected Firm Load or Guaranteed Interruptible load, but they must give 12 months written notice to do so. For example, if a customer designated 30,000 kV.A as their Protected Firm Load and wanted to increase it to 35,000 kV.A, they would have to give 12 months written notice before the change would take effect.

It is also possible that the two situations could occur for the same customer. For example a customer goes off CRP on March 1, 2014 and then a year later on April 1, 2015 comes back on CRP. If the customer then decided three months later (on July 1, 2015) that they wanted to re-designate their Protected Firm Load from 30,000 kV.A to 35,000 kV.A, they would still be required to submit a written request to have the change effective in 12 months (July 1, 2016).

Section:	Tab 6: Appendix 6.11	Page No.:	4
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Program Participation		

PREAMBLE TO IR (IF ANY):

QUESTION:

It is noted that there continue to be 3 customers on the Curtailable Rate Program for 2013/14. Have any other customers expressed an interest in the program or likely to want to join the program in the foreseeable future?

RATIONALE FOR QUESTION:

To understand the likely level of program participation in the future.

RESPONSE:

A number of customers have expressed interest in the Curtailable Rate Program and would consider joining in the program in the foreseeable future.

Section:	Tab 6: Appendix 6.11	Page No.:	4
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	Program Participation		

PREAMBLE TO IR (IF ANY):

QUESTION:

If so, please describe what options these customers are interested in.

RATIONALE FOR QUESTION:

To understand the likely level of program participation in the future.

RESPONSE:

The majority of customer interest has revolved around Options A and R, and to a lesser extent, interest in Option E.

Section:	Tab 6: Appendix 6.11	Page No.:	9-10
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	CRP Reference Discount Value		

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on the cost estimates for an SCCT presented in the recent NFAT proceeding, please estimate the annual carrying cost of an SCCT ($/kW) expressed in real 2013/14 dollars.

RATIONALE FOR QUESTION:

To check the validity of the value proposed by Manitoba Hydro for the CRP Reference Discount.

RESPONSE:

The estimated annual carrying cost for a GE LM6000 SCCT, assuming a 50 MW net winter peak capacity is $123/kW/year (real 2013$).

Section:	Tab 6: Appendix 6.11	**Page No.:**	9-10
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Curtailable Rates		
Issue:	CRP Reference Discount Value		

PREAMBLE TO IR (IF ANY):

QUESTION:

Has Manitoba Hydro recently reviewed the 42% factor which is used to convert the annual cost of an SCCT into the Reference Discount for the CRP? If yes, please provide a copy of the review. If no, please explain why the 42% is still considered to be appropriate.

RATIONALE FOR QUESTION:

To check the validity of the value proposed by Manitoba Hydro for the CRP Reference Discount.

RESPONSE:

The application of the 42% factor provides a result which recognizes that curtailable load does not have the same characteristics as a SCCT. A SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during drought or extended emergency situations. Over the following year, Manitoba Hydro plans to review the value attributable to the Curtailable Rate Program.

Please also see Manitoba Hydro responses to MIPUG/MH-I-29a and MIPUG/MH-I-29c.

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	3 5
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast and Actual Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 5, please provide a schedule that contrasts the Residential customer count forecast as set out in the 2011 Load Forecast with that of the current Load Forecast. In the case of the 2014 Load Forecast please report actual values where available. Please explain the reasons for the variance in: i) the subsequent actual values versus the 2011 forecast and ii) the variance, for 2014/15 forward, between the 2011 and the 2014 forecasts.

RATIONALE FOR QUESTION:

To understand the reasons for changes in customer count and energy use as between forecasts and between the historic and forecast periods. Questions are distinct from PUB/MH 1-54 – 1-60.

RESPONSE:

The following table displays the forecast of customers for the Residential Sector of both the 2011 Forecast and the 2014 forecast.

i) There is little variance between the 2011 Forecast and the three years of actuals in the residential group, with Residential Basic forecast being 0.2% lower (921 customers), Residential Diesel being 3% lower (19 customers) and Residential Seasonal being 3% higher (704 customers) compared to actual.

ii) The variance between the 2011 Residential Basic Forecast and the 2014 Forecast are primarily driven by changes in the population forecast from 2011 to 2014. The diesel and seasonal customer forecasts are reviewed and updated based upon historical growth and the 2014 Forecast reflects the expected growth in each sector.

Fiscal Year	2011 Residential Forecast			2014 Residential Forecast		
	Basic	Diesel	Seasonal	Basic	Diesel	Seasonal
2011/12	450,399	554	21,111	450,748	568	20,844
2012/13	455,614	559	21,286	456,130	577	20,731
2013/14	461,353	564	21,461	462,274	583	20,757
2014/15	467,089	570	21,636	468,076	587	20,814
2015/16	472,941	575	21,811	473,761	595	20,914
2016/17	478,890	580	21,986	479,963	603	21,014
2017/18	484,868	586	22,161	486,387	611	21,114
2018/19	490,811	591	22,336	492,700	619	21,214
2019/20	496,708	596	22,511	498,887	627	21,314
2020/21	502,547	602	22,686	504,914	635	21,414
2021/22	508,313	607	22,861	510,687	643	21,514
2022/23	513,994	612	23,036	516,160	652	21,614
2023/24	519,576	617	23,211	521,337	660	21,714
2024/25	525,046	623	23,386	526,282	668	21,814
2025/26	530,395	628	23,561	531,016	676	21,914
2026/27	535,617	633	23,736	535,517	684	22,014
2027/28	540,705	639	23,911	539,802	692	22,114
2028/29	545,658	644	24,086	543,914	700	22,214
2029/30	550,471	649	24,261	547,924	708	22,314
2030/31	555,142	655	24,436	551,878	716	22,414
2031/32				555,807	724	22,514
2032/33				559,731	732	22,614
2033/34				563,659	740	22,714

Indicates actuals

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	3 5
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast and Actual Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Tab 7, page 3, please outline the factors that explain the difference between the historic 20-year Residential growth rate of 1.6%/annum (including DSM impacts) and the projected growth rate of 0.9%/annum (including DSM impacts). How much is due differences in population/customer count growth, use per customer (prior to DSM reductions) and the impact of DSM as between the two periods?

RATIONALE FOR QUESTION:

To understand the reasons for changes in customer count and energy use as between forecasts and between the historic and forecast periods. Questions are distinct from PUB/MH 1-54 – 1-60.

RESPONSE:

The historic 20 year Residential Basic growth rate of 1.6% per year is comprised of:

0.8% annual customer growth due to population
1.1% annual growth due to increase average use
-0.3% due to DSM Program savings

The forecast 20 year Residential Basic growth rate of 0.9% per year is comprised of:

1.0% annual customer growth due to population
0.2% annual growth due to increase average use
-0.3% due to DSM Program savings

Section:	Tab 7: Appendix 7.1	**Page No.:**	60-61
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 61, please provide a schedule that for the last ten historic years sets out:

i. Total Residential Basic use – actual and weather adjusted
ii. Total Impact of DSM programs
iii. Total impact of Codes and Standards
iv. Resulting Residential Basic gross use ((i.e., (i) + (ii) + (iii))

RATIONALE FOR QUESTION:

To obtain a better understanding of the Residential load forecast methodology.

RESPONSE:

Please see the table below.

Residential Basic Historical information

Fiscal Year	Actual Usage (GW.h)	W/A Usage (GW.h)	DSM Programs (GW.h)	Codes and Standards (GW.h)	Gross Total (GW.h)
2004/05	6,275	6,305	57	135	6,496
2005/06	6,171	6,442	70	154	6,666
2006/07	6,443	6,442	90	175	6,707
2007/08	6,736	6,674	114	199	6,987
2008/09	6,847	6,710	151	225	7,086
2009/10	6,786	6,940	192	267	7,399
2010/11	6,952	7,053	217	312	7,581
2011/12	6,818	7,137	247	362	7,746
2012/13	7,223	7,228	270	412	7,910
2013/14	7,767	7,249	294	466	8,009

Section:	Tab 7: Appendix 7.1	**Page No.:**	60-61
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1 – pages 60-61, please provide a schedule that sets out the annual historic ratio of Electric Heat Customer Count to Total Residential Basic Customer Count for the last 20 years and the ratio's projected value for each of the forecast years.

RATIONALE FOR QUESTION:

To obtain a better understanding of the Residential load forecast methodology.

RESPONSE:

The residential load forecast methodology was calibrated to the results of the 2009 Residential Survey and in the development of the forecast, the historical information was only estimated back to 2009/10. Please see the table below.

Residential Basic Customers

Fiscal Year	Electric Heat Customers	Other Customers	Total	Electric Heat Ratio
2009/10	153,132	288,578	441,710	34.7%
2010/11	156,708	289,174	445,882	35.1%
2011/12	160,600	290,148	450,748	35.6%
2012/13	164,994	291,136	456,130	36.2%
2013/14	169,582	292,692	462,274	36.7%
2014/15	173,561	294,514	468,075	37.1%
2015/16	177,387	296,375	473,762	37.4%
2016/17	181,184	298,780	479,964	37.7%
2017/18	184,929	301,458	486,387	38.0%
2018/19	188,478	304,222	492,700	38.3%
2019/20	191,795	307,092	498,887	38.4%
2020/21	194,868	310,046	504,914	38.6%
2021/22	197,696	312,991	510,687	38.7%
2022/23	200,277	315,883	516,160	38.8%
2023/24	202,640	318,697	521,337	38.9%
2024/25	204,859	321,424	526,283	38.9%
2025/26	206,970	324,046	531,016	39.0%
2026/27	208,970	326,547	535,517	39.0%
2027/28	210,869	328,932	539,801	39.1%
2028/29	212,686	331,228	543,914	39.1%
2029/30	214,445	333,479	547,924	39.1%
2030/31	216,165	335,713	551,878	39.2%
2031/32	217,856	337,951	555,807	39.2%
2032/33	219,528	340,203	559,731	39.2%
2033/34	221,184	342,474	563,658	39.2%

Section:	Tab 7: Appendix 7.1	Page No.:	60-61
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

Is the forecast ratio used in the determination of average use based solely on the modelling described on page 60 and are any adjustments to the forecast for the Heating Fuel Choice Initiative made separately as part of the impact of DSM?

RATIONALE FOR QUESTION:

To obtain a better understanding of the Residential load forecast methodology.

RESPONSE:

The forecast ratio of Electric Heat Billed is based on the modeling described on page 60 of Appendix 7.1. The expected impact of the Heating Fuel Choice Initiative is then applied to this forecast ratio in Step 10 described on page 61, and the final ratio including the effects of the initiative is what is used in the forecast.

The Heating Fuel Choice Initiative, noted at Step 10 on page 61 of Appendix 7.1, is considered to be an education campaign and its effect is included in the forecast. It is separate from the DSM Programs presented under the 2014-2017 Power Smart Plan.

Section:	Tab 7: Appendix 7.1	**Page No.:**	60-61
Topic:	Electric Load Forecast		
Subtopic:	Residential		
Issue:	Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 61, please provide a schedule that sets out for each forecast year (starting with 2014/15):

i. The forecast overall average Residential use.
ii. The forecast number of dwellings,
iii. The product of items (i) and (ii),
iv. The annual estimated savings from the Heating Fuel Choice Initiative,
v. The forecast impact of new codes and standards,
vi. The Future use of Electric Vehicles in the Residential sector impact, and
vii. The resulting Residential Basic customer total energy use (i.e., (iii)-(iv)-(v)+(vi)).

RATIONALE FOR QUESTION:

To obtain a better understanding of the Residential load forecast methodology.

RESPONSE:

Please see the table below.

Residential Basic

Fiscal Year	Overall Average Use (kW.h)	# of Dwellings	Total Usage (GW.h)	Forecast Reduction from the Heating Fuel Choice Initiative (GW.h)	Forecast Codes and Standards (GW.h)	Electric Vehicle in Residential (GW.h)	Residential Basic Total Energy Use (GW.h)
2014/15	15,988	465,701	7,445	-18	-48	0.3	7,380
2015/16	16,158	471,386	7,617	-29	-107	0.4	7,481
2016/17	16,377	477,588	7,821	-42	-174	0.7	7,606
2017/18	16,555	484,012	8,013	-57	-231	1.0	7,726
2018/19	16,697	490,325	8,187	-75	-278	1.4	7,836
2019/20	16,834	496,512	8,358	-96	-318	1.8	7,946
2020/21	16,952	502,539	8,519	-118	-355	2.3	8,049
2021/22	17,066	508,312	8,675	-140	-387	3.0	8,151
2022/23	17,177	513,785	8,825	-163	-417	3.7	8,248
2023/24	17,285	518,962	8,970	-187	-446	4.7	8,342
2024/25	17,393	523,908	9,112	-209	-474	5.8	8,435
2025/26	17,500	528,641	9,251	-231	-501	7.2	8,527
2026/27	17,608	533,143	9,387	-251	-526	8.9	8,619
2027/28	17,716	537,427	9,521	-272	-549	10.9	8,711
2028/29	17,825	541,539	9,653	-291	-573	13.4	8,802
2029/30	17,934	545,550	9,784	-310	-595	16.4	8,895
2030/31	18,043	549,503	9,915	-329	-615	20.0	8,990
2031/32	18,151	553,432	10,045	-348	-635	24.4	9,087
2032/33	18,259	557,356	10,177	-366	-654	29.8	9,186
2033/34	18,367	561,284	10,309	-385	-672	36.3	9,289

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4-5 5
Topic:	Electric Load Forecast		
Subtopic:	General Service Sector – Mass Market		
Issue:	Forecast and Actual Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 5, please provide a schedule that contrasts the Mass Market customer count forecast as set out in the 2011 Load Forecast with that of the current Load Forecast. In the case of the 2014 Load Forecast please report actual values where available. Please explain the reasons for the variance in: i) the subsequent actual values versus the 2011 forecast and ii) the variance, for 2014/15 forward, between the 2011 and the 2014 forecasts.

RATIONALE FOR QUESTION:

To understand the reasons for changes in customer count and energy use as between forecasts and between the historic and forecast periods.

RESPONSE:

Please see the following table.

Fiscal Year	2011 Mass Market Forecast	2014 Mass Market Forecast	Variance: Forecast to Actuals
2011/12	65,742	65,546	0.3%
2012/13	66,322	65,974	0.5%
2013/14	66,989	66,569	0.6%
2014/15	67,638	67,125	
2015/16	68,288	67,670	
2016/17	68,930	68,267	
2017/18	69,561	68,902	
2018/19	70,159	69,530	
2019/20	70,733	70,119	
2020/21	71,299	70,655	
2021/22	71,856	71,144	
2022/23	72,404	71,599	
2023/24	72,941	72,029	
2024/25	73,465	72,438	
2025/26	73,976	72,828	
2026/27	74,475	73,197	
2027/28	74,960	73,547	
2028/29	75,431	73,884	
2029/30	75,887	74,210	
2030/31	76,330	74,532	
2031/32		74,850	
2032/33		75,168	
2033/34		75,485	

indicates actuals

The 2011 forecast for Mass Market customers in 2013/14 was 0.6% higher (420 customers) than actual.

The 2014 Forecast for Mass Market customers is lower than presented under the 2011 Forecast due to the 2014 Forecast including a lower Residential customer forecast and a reduction to the GDP forecast when compared to the 2011 Forecast, as both affect the Mass Market customer forecast.

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4-5 5
Topic:	Electric Load Forecast		
Subtopic:	General Service Sector – Mass Market		
Issue:	Forecast and Actual Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Tab 7, pages 4-5, please indicate separately the historic 20-year energy growth rates for the Mass Market and Top Consumer segments. In the same schedule please set out the forecast 20-year energy growth rate for each segment both before and after DSM program impacts are included.

RATIONALE FOR QUESTION:

To understand the reasons for changes in customer count and energy use as between forecasts and between the historic and forecast periods.

RESPONSE:

Mass Market	
Historic growth rate (20 years):	1.6%
Forecast growth rate (20 years):	1.4%
Forecast growth rate (20 years including DSM programs):	0.6%

Top Consumers	
Historic growth rate (20 years):	1.9%
Forecast growth rate (20 years):	2.0%
Forecast growth rate (20 years including DSM programs):	1.8%

Section:	Tab 7 Tab 7: Appendix 7.1	**Page No.:**	4-5 5
Topic:	Electric Load Forecast		
Subtopic:	General Service Sector – Mass Market		
Issue:	Forecast and Actual Variances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please outline the factors that explain the difference between the historic 20-year Mass Market growth rate (including DSM impacts) and the projected 20-year growth rate (including DSM impacts). How much is due differences in economic/customer count growth, use per customer (prior to DSM reductions) and the impact of DSM as between the two periods?

RATIONALE FOR QUESTION:

To understand the reasons for changes in customer count and energy use as between forecasts and between the historic and forecast periods.

RESPONSE:

The historic 20 year Mass Market growth rate of 1.6% per year is comprised of:

- 0.7% annual growth due to economic/customer growth
- 1.3% annual growth due to increased average use
- -0.4% due to DSM Program savings

The forecast 20 year Mass Market growth rate of 0.6% per year is comprised of:

- 0.6% annual growth due to economic/customer growth
- 0.8% annual growth due to increased average use
- -0.8% due to DSM Program savings

Section:	Tab 7: Appendix 7.1	**Page No.:**	
Topic:	Electric Load Forecast		
Subtopic:	General Service Sector – Mass Market		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, pages 63-64, please provide a schedule that for the last ten historic years sets out for each of the customer class groupings used by Manitoba Hydro (i.e., Small-ND, Small-D & Medium and Large):

i. Total Use – actual and weather adjusted
ii. Total Impact of DSM programs
iii. Total impact of Codes and Standards
iv. Resulting Total use ((i.e., (i) + (ii) + (iii))

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the General Service – Mass Market Sector.

RESPONSE:

Manitoba Hydro currently only applies the historical DSM and Codes and Standards to the General Service Mass Market class and it is not broken down by rate class. The following two tables provide the actual and weather adjusted usage by rate class and the total impact of DSM Programs and Codes and Standard to the General Service Mass Market sector.

Fiscal Year	GS Small Non Demand Usage (GW.h)	GS Small Non Demand W/A Usage (GW.h)	GS Small Demand Usage (GW.h)	GS Small Demand W/A Usage (GW.h)	GS Medium Usage (GW.h)	GS Medium W/A Usage (GW.h)	GS Large Usage (GW.h)	GS Large W/A Usage (GW.h)
2004/05	1400	1414	1832	1841	2790	2813	1494	1498
2005/06	1321	1354	1931	1978	2790	2827	1545	1553
2006/07	1535	1536	1805	1793	2920	2907	1580	1573
2007/08	1570	1557	1882	1873	2950	2937	1605	1601
2008/09	1583	1567	1901	1886	2942	2937	1623	1623
2009/10	1560	1589	1880	1911	2920	2957	1625	1652
2010/11	1595	1611	1924	1941	2981	3000	1758	1760
2011/12	1551	1591	1924	1967	2960	2986	1726	1734
2012/13	1628	1622	2016	2013	3002	2988	1788	1783
2013/14	1722	1645	2143	2060	3155	3081	1819	1801

GS Mass Market

Fiscal Year	Usage (GW.h)	W/A Usage (GW.h)	DSM Programs (GW.h)	Codes and Standards (GW.h)	Gross Total (GW.h)
2004/05	7516	7565	381	106	8052
2005/06	7587	7712	436	108	8256
2006/07	7839	7809	486	110	8405
2007/08	8006	7968	534	110	8612
2008/09	8049	8013	582	110	8706
2009/10	7985	8108	631	111	8850
2010/11	8258	8313	684	111	9108
2011/12	8162	8278	737	124	9139
2012/13	8434	8407	825	139	9371
2013/14	8839	8587	892	149	9628

Section:	Tab 7: Appendix 7.1	Page No.:	
Topic:	Electric Load Forecast		
Subtopic:	General Service Sector – Mass Market		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 61, please a schedule that for each customer class sets out for each forecast year (starting with 2014/15):

i. The forecast overall average use.
ii. The forecast number of customers,
iii. The product to items (i) and (ii),
iv. The forecast impact of new codes and standards,
v. The Future use of Electric Vehicles in the Mass Market sector, and
vi. The resulting customer class total energy use (i.e., (iii)-(iv)+(v)).

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the General Service – Mass Market Sector.

RESPONSE:

Manitoba Hydro combines the Small Non Demand, Small Demand and Medium customers for its load forecasting methodology described at page 62 and 63 of Tab 7 Appendix 7.1 and does not have the requested information for each separate customer class. Manitoba Hydro has provided the combined customer information below.

	Small Non-Demand, Small-Demand and Medium					
Fiscal Year	Average Number of Customers	Overall Average Use (kW.h)	W/A Usage (GW.h)	Codes and Standards (GW.h)	Electric Vehicles (GW.h)	Total Energy Use (GW.h)
2014/15	66,789	104,058	6,950	22	0.5	6,928
2015/16	67,327	105,428	7,098	45	1.0	7,055
2016/17	67,916	106,983	7,266	75	1.8	7,193
2017/18	68,542	108,509	7,437	112	2.5	7,328
2018/19	69,162	109,743	7,590	149	3.4	7,445
2019/20	69,745	110,748	7,724	185	4.3	7,543
2020/21	70,274	111,651	7,846	222	5.4	7,629
2021/22	70,758	112,552	7,964	259	6.6	7,712
2022/23	71,208	113,451	8,079	295	8.0	7,791
2023/24	71,631	114,351	8,191	332	9.6	7,869
2024/25	72,034	115,253	8,302	369	11.4	7,945
2025/26	72,418	116,157	8,412	405	13.6	8,020
2026/27	72,781	117,062	8,520	442	16.2	8,094
2027/28	73,125	117,970	8,627	478	19.2	8,168
2028/29	73,455	118,881	8,732	514	22.8	8,241
2029/30	73,775	119,796	8,838	551	27.1	8,314
2030/31	74,089	120,716	8,944	587	32.2	8,389
2031/32	74,401	121,641	9,050	623	38.3	8,465
2032/33	74,712	122,571	9,157	660	45.6	8,543
2033/34	75,021	123,506	9,266	696	54.4	8,624

Large Mass Market

Fiscal Year	Average Number of Customers	Overall Average Use (kW.h)	W/A Usage (GW.h)	Codes and Standards (GW.h)	Electric Vehicles (GW.h)	Total Energy Use (GW.h)
2014/15	336	5,618,309	1,886	-	-	1,886
2015/16	343	5,653,077	1,938	-	-	1,938
2016/17	351	5,689,606	1,998	-	-	1,998
2017/18	360	5,724,432	2,060	-	-	2,060
2018/19	368	5,752,381	2,115	-	-	2,115
2019/20	374	5,776,333	2,162	-	-	2,162
2020/21	380	5,798,068	2,204	-	-	2,204
2021/22	386	5,819,815	2,246	-	-	2,246
2022/23	392	5,841,109	2,288	-	-	2,288
2023/24	398	5,862,201	2,330	-	-	2,330
2024/25	404	5,883,641	2,375	-	-	2,375
2025/26	410	5,905,077	2,421	-	-	2,421
2026/27	416	5,925,894	2,465	-	-	2,465
2027/28	423	5,947,121	2,513	-	-	2,513
2028/29	429	5,968,049	2,560	-	-	2,560
2029/30	435	5,988,787	2,607	-	-	2,607
2030/31	442	6,009,706	2,657	-	-	2,657
2031/32	449	6,030,433	2,707	-	-	2,707
2032/33	456	6,051,064	2,757	-	-	2,757
2033/34	463	6,071,683	2,809	-	-	2,809

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to the forecast Pipeline sector load increase referenced in Tab 7, page 4, does Appendix 7.1 - Table 16 capture this in the Individual Load forecast or the PLIL forecast?

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

The anticipated committed load growth in the Pipelines sector referenced on page 4 of Tab 7 of the Application, representing 1 194 GW.h of growth as noted at page ii of Appendix 7.1, is captured within the forecast of the individual customers that make up the Top Consumers. The additional load growth forecast as PLIL is not industry specific.

Section:	Tab 7 Tab 7: Appendix 7.1	**Page No.:**	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

In each year of the forecast, what is the specific contribution of the new Pipeline sector load?

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

Please refer to the Petrol/Oil/Natural Gas column from 2013/14 to 2019/20 in Manitoba Hydro's response to PUB/MH I-54b, which includes the pipeline load for Top Consumers.

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to Appendix 7.1, page 65, please explain how the total load model is used to forecast PLIL. In doing so please use 2017/18 as an illustrative example.

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

The model for total load of Top Consumers, as described on page 65 of Appendix 7.1, is:

Log Total Load = 1.477 – 0.426 * Log Top Price + 0.862 * LGDP

The forecast of future load for the Top Consumers using this equation needs the forecast of the average price in cents per kW.h along with a forecast of the expected real GDP. This gives a forecast without DSM, so the Top Consumers DSM to date needs to be added. The model is then calibrated to the last year of history (2013/14) which is done with a starting point adjustment (i.e. a constant) that is added to ensure that the year 2013/14 starts with the correct value.

The Top Consumers total load is calculated for 2016/17 and 2017/18 as follows:

Forecast values:

Top Consumers Average Price: 2016/17 = 4.221 cents/kW.h

Top Consumers Average Price: 2017/18 = 4.303 cents/kW.h

Read GDP: 2016/17 = average(1831.89 Cdn GDP, 17317.62 US GDP) = 9574.8

Read GDP: 2017/18 = average(1877.43 Cdn GDP, 17818.99 US GDP) = 9848.2

Cumulative Top Consumers DSM to 2013/14 = 316 GW.h

2013/14 Starting Point Adjustment = 282 GW.h

Putting these into the equation gives:

Forecast of Top Consumers for 2016/17 =

$$\exp(1.477 - 0.42624 * \ln(4.221) + 0.8618 * \ln(9574.8)) -316 - 282 = 5797 \text{ GW.h}$$

Forecast of Top Consumers for 2017/18 =

$$\exp(1.477 - 0.42624 * \ln(4.303) + 0.8618 * \ln(9848.2)) -316 - 282 = 5900 \text{ GW.h}$$

(Note: coefficients are shown to more decimals so that the calculation will not round off).

PLIL is taken as the long term growth of the Top Consumers. So PLIL for 2017/18 would be taken as the difference between Top Consumers in 2016/17 and 2017/18:

= 5900 – 5797 = 103 GW.h

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

Using the model on page 65 and the current forecast values for Top Price and LGDP, what would be the total Top Consumer load forecast for each year from 2014/15 to 2033/34?

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

The following table presents forecast growth using solely the equation presented on page 65 of Appendix 7.1, and applying the start year adjustment and subtraction of the cumulative DSM to 2013/14. Note that Manitoba Hydro does not introduce the PLIL forecast until year 4 of the forecast (2017/18 for the 2014 Forecast). To compare these values to the PLIL forecast presented under the 2014 Forecast as shown in Table 16 in Appendix 7.1, the 2016/17 value (5 797 GW.h) presented below should be subtracted from any forecast year results.

Year	GW.h
2014/15	5583
2015/16	5690
2016/17	5797
2017/18	5900

Year	GW.h
2018/19	5991
2019/20	6074
2020/21	6158
2021/22	6242
2022/23	6327
2023/24	6413
2024/25	6501
2025/26	6589
2026/27	6679
2027/28	6770
2028/29	6862
2029/30	6955
2030/31	7049
2031/32	7145
2032/33	7241
2033/34	7339

Section:	Tab 7 Tab 7: Appendix 7.1	Page No.:	4 21 & 65
Topic:	Electric Load Forecast		
Subtopic:	Top Consumers		
Issue:	Load Forecast Methodology		

PREAMBLE TO IR (IF ANY):

QUESTION:

Is the introduction of TOU rates for large customers in 2016/17 expected to have any impact on the load forecast? If not, explain why not? If yes, has any such impact been incorporated in the current forecast?

RATIONALE FOR QUESTION:

To obtain a better understanding of the load forecast methodology as used for the Top Consumer Sector. The credibility of the forecast goes to the credibility of the application.

RESPONSE:

The introduction of Time-of-Use rates for large customers in 2016/17 is not expected to have a material impact on overall energy consumption by these customers in the short term due to the rate neutral implementation planned for these rates.

In the long term, customers may adapt their operations to respond to the price signals provided through the rate structure or capture potential benefits within the rate structure. Some customers may seek to expand their participation in Manitoba Hydro's Industrial Power Smart Programs in an effort to reduce the consumption of higher cost on-peak energy. Conversely, some customers may seek to increase consumption of off-peak energy to expand production or shift energy requirements to lower cost off-peak rates, but load shifting will have no material impact to overall energy consumption.

In most instances, increased consumption during the off-peak period will require customer investment in infrastructure and processes that will provide Manitoba Hydro with sufficient lead time to incorporate potential load changes into future load forecasts. In any instance, such increases are not anticipated to significantly change the long-term forecast.

Section:	Tab 5: Appendix 5.1 Tab 8: Appendix 8.2 Tab 11, Appendix 11.44	Page No.:	103 (j)
Topic:	Demand Side Management		
Subtopic:	Affordable Energy Fund (AEF)		
Issue:	Accounting Treatment and Projected Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

How does Manitoba Hydro determine the programs/initiatives that will be “charged” to the AEF in any given year?

RATIONALE FOR QUESTION:

To clarify the usage and future outlook for the Affordable Energy Fund.

RESPONSE:

The allocations of funds from the Affordable Energy Fund are determined in consultation with the Minister responsible for Manitoba Hydro. The allocation of the Fund by program is provided in Appendix 11.44 – DSM MFR 2.

Section:	Tab 5: Appendix 5.1 Tab 8: Appendix 8.2 Tab 11, Appendix 11.44	Page No.:	103 (j)
Topic:	Demand Side Management		
Subtopic:	Affordable Energy Fund (AEF)		
Issue:	Accounting Treatment and Projected Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain and contrast the accounting treatment for Affordable Energy Fund expenditures as compared to other DSM expenditures. (i.e., are AEF expenditures charged directly to the fund as opposed to being deferred and amortized as is the case with other DSM expenditures?).

RATIONALE FOR QUESTION:

To clarify the usage and future outlook for the Affordable Energy Fund.

RESPONSE:

In 2007, Manitoba Hydro established an Affordable Energy Fund (AEF) in the initial amount of $35 million. For accounting purposes, the AEF is classified as an asset with an offsetting liability. Annual expenditures are charged directly against the liability. The offsetting asset is amortized at the same rate as the expenditures draw down the liability.

All DSM expenditures are charged to a rate regulated asset when the expenditures are incurred and are subsequently amortized on a straight-line basis over a period of 10 years.

Section:	Tab 5: Appendix 5.1 Tab 8: Appendix 8.2 Tab 11, Appendix 11.44	Page No.:	103 (j)
Topic:	Demand Side Management		
Subtopic:	Affordable Energy Fund (AEF)		
Issue:	Accounting Treatment and Projected Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Does interest accrue each year on the remaining balance in the AEF?

RATIONALE FOR QUESTION:

To clarify the usage and future outlook for the Affordable Energy Fund.

RESPONSE:

Interest is accrued on the outstanding balance each month.

Section:	Tab 5: Appendix 5.1 Tab 8: Appendix 8.2 Tab 11, Appendix 11.44	Page No.:	103 (j)
Topic:	Demand Side Management		
Subtopic:	Affordable Energy Fund (AEF)		
Issue:	Accounting Treatment and Projected Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on the 2014-2017 Power Smart Plan (and the associated 15-year outlook) when will the Affordable Energy Fund be fully depleted?

RATIONALE FOR QUESTION:

To clarify the usage and future outlook for the Affordable Energy Fund.

RESPONSE:

The forecast of the Affordable Energy Fund is provided in the Power Smart Plan on page 34 of Appendix 8.1. The Fund is forecast to be fully depleted in 2027/28.

Section:	Tab 5: Appendix 5.1 Tab 8: Appendix 8.2 Tab 11, Appendix 11.44	Page No.:	103 (j)
Topic:	Demand Side Management		
Subtopic:	Affordable Energy Fund (AEF)		
Issue:	Accounting Treatment and Projected Balances		

PREAMBLE TO IR (IF ANY):

QUESTION:

Once the funds in the AEF have been completely depleted will the programs that it currently supports be continued and funded as any other DSM program?

RATIONALE FOR QUESTION:

To clarify the usage and future outlook for the Affordable Energy Fund.

RESPONSE:

A decision on how the programs currently funded under the Affordable Energy Fund will be funded or continued once the funds have been depleted, has not been made at this time.

Section:	Tab 8: Appendix 8.1 Tab 8: Appendix 8.2	**Page No.:**	10 67
Topic:	Demand Side Management		
Subtopic:	DSM Metrics		
Issue:	Long Run Marginal Cost		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the updated marginal costs used to evaluate DSM programs as discussed in Appendix 8.1, page 10. In doing so please provide:

i. the marginal cost values for generation, transmission and distribution.
ii. the resulting total marginal cost associated with a transmission-connected customer (as measured at the point of delivery).
iii. the resulting total marginal cost associated with a distribution-connected customer (as measured as the point of delivery).
iv. the basis on which the marginal cost are quoted (e.g., in what year's dollars, are the values real or nominal, and over what period where they calculated).

RATIONALE FOR QUESTION:

Marginal Costs are used in the evaluation of DSM programs.

RESPONSE:

i. Manitoba Hydro's levelized marginal cost values are as follows:

Generation	6.10¢/kWh
Transmission	0.65¢/kWh
Distribution	0.77¢/kWh

ii. The levelized marginal cost associated with a transmission-connected customer (as measured at the point of delivery) is 6.75¢/kWh.

iii. The levelized marginal cost associated with a distribution-connected customer (as measured as the point of delivery) is 7.52¢/kWh.

iv. The marginal cost values are in 2014 real dollars and they are levelized over a thirty-year period (2014/15 to 2043/44) using a discount rate of 5.4%.

Section:	Tab 8: Appendix 8.1 Tab 8: Appendix 8.2	**Page No.:**	10 67
Topic:	Demand Side Management		
Subtopic:	DSM Metrics		
Issue:	Long Run Marginal Cost		

PREAMBLE TO IR (IF ANY):

QUESTION:

Were these same marginal cost values used in the calculation of the Utility Marginal Benefits as described in Appendix 8.2 (Exhibit 4.4.1.3-B)? If not, what values were used for the 2012/13 Power Smart Annual Review and what were they based on?

RATIONALE FOR QUESTION:

Marginal Costs are used in the evaluation of DSM programs.

RESPONSE:

The marginal values contained in the 2014-17 Power Smart Plan (provided in Manitoba Hydro's response to COALITION/MH-I-67a) were not used for the 2012/13 Power Smart Annual Review. Programs are evaluated using the same marginal values that were used when creating the Power Smart Plan.

For the 2012/13 Power Smart Annual Review, a levelized marginal value of 7.74¢ (2012 dollars) was used with the following breakdown:

Generation	6.32¢/kWh
Transmission	0.65¢/kWh
Distribution	0.77¢/kWh

Section:	Tab 8: Appendix 8.1	Page No.:	Executive Summary
Topic:	Demand Side Management		
Subtopic:	DSM Metrics		
Issue:	Applicable Period		

PREAMBLE TO IR (IF ANY):

QUESTION:

The Executive Summary of Appendix 8.1 references an overall electric Power Smart portfolio TRC of 2.2, a RIM of 1.0 and a levelized cost of 1.8 cents per kilowatt hour. Are these values based on the entire 2014 to 2029 period or just 2014-2017?

RATIONALE FOR QUESTION:

To clarify the basis for the DSM metrics values quoted.

RESPONSE:

DSM program metrics are determined using a 30-year stream of savings and costs. The metrics in Appendix 8.1 are based on values in 2014/15 to 2043/44.

Section:	Tab 8: Appendix 8.1	**Page No.:**	Executive Summary
Topic:	Demand Side Management		
Subtopic:	DSM Metrics		
Issue:	Applicable Period		

PREAMBLE TO IR (IF ANY):

QUESTION:

If based on the 2014-2029 period, what at the values for the electric Power Smart programs initiated in the first three years (i.e., 2014/15 to 2016/17)?

RATIONALE FOR QUESTION:

To clarify the basis for the DSM metrics values quoted.

RESPONSE:

The metrics of achieving DSM savings are only meaningful over the life of a program. As such, isolating a three year period within a long-term plan and calculating short-term program and portfolio metrics is not a meaningful exercise and the requested information is not readily available.

Section:	Tab 8: Appendix 8.1	**Page No.:**	
Topic:	Demand Side Management		
Subtopic:	2014-2017 Power Smart Plan		
Issue:	Copy of Plan		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a copy of the Power Smart Plan 2014-2017.

RATIONALE FOR QUESTION:

The Application contains the Power Smart Plan 2014-2017 Supplemental Report but not the actual Power Smart Plan 2014-2017.

RESPONSE:

Please find attached a copy of the Power Smart Plan 2014-2017. Manitoba Hydro has also included as attachment 2 a copy of the Power Smart Plan for fiscal year 2015-2016.

Power Smart Plan

2014 to 2017

Manitoba Hydro's energy efficiency initiatives for the next three years.

Manitoba Hydro POWER SMART

2014-2017 Power Smart Plan

Highlights

Manitoba Hydro has been successfully delivering demand side management (DSM) for over 20 years in an effort to meet the energy needs of Manitoba in a more sustainable manner while assisting customers to use energy more efficiently and to reduce their energy bills. Manitoba Hydro has a strong commitment to DSM with a focus on pursuing all cost effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities that may become economically viable.

To ensure that Manitoba Hydro maintains its DSM leadership position in the future, and as part of the annual DSM planning process, Manitoba Hydro staff undertook an extensive assessment of the Manitoba market to identify any additional energy efficiency opportunities that may remain. The result is an expanded and updated DSM plan that outlines Manitoba Hydro's DSM forecast for the next 3 years: April 2014 through to March 31, 2017. To achieve these increased energy savings, Manitoba Hydro has or plans to introduce new initiatives and implement enhancements to existing initiatives. A few of these initiatives are highlighted below:

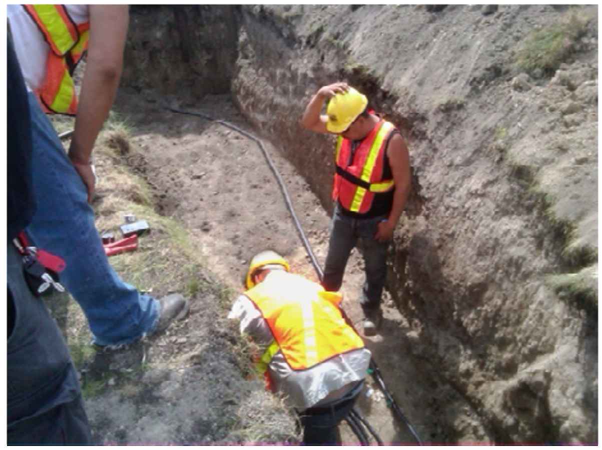
Neighbourhood Power Smart Project in William Whyte

Building on the success of the Neighbourhood Power Smart Project in William Whyte, Manitoba Hydro is committed to further increase participation by 100 homes in 2014/15. Working with North End Community Renewal Corporation, lower income customers can benefit from energy efficient upgrades with the assistance of a Community Coordinator and Social Enterprise Contractors completing the retrofits. This community-led initiative helps to reduce barriers to participate with a door-to-door approach and provides employment opportunities to members of the community.

LED Roadway Lighting Conversion Program

Manitoba Hydro has approved a spring launch of a LED Roadway Lighting Conversion Program. Under this initiative, in working with Manitoba municipalities and local governments, Manitoba Hydro will convert all HPS roadway lighting (less than 1000 W) to energy efficient LED technologies over the next 7 years. This initiative is anticipated to achieve 35 GW.h in electricity savings and 5 MW in winter peak demand savings through a utility investment of $40.4 million. In addition to energy savings, LED roadway lighting has a longer life than HPS lighting, quick turn on and off, and improved performance in colder temperature settings. LEDs also provide the added benefit of reduced glare as directing the light downward onto the roadway reduces the amount of light that is directed into drivers' eyes.

Community Geothermal Program



The Community Geothermal Program, launched in June 2013, is based on a pilot conducted in partnership with AKI Energy, an Aboriginal social enterprise group focused on building a green economy in First Nations communities. Through the program, Manitoba Hydro works with community organizations such as AKI Energy to coordinate multiple geothermal heat pump installations within a community in order to reduce installation costs through bulk purchases and increased local industry capacity. Manitoba Hydro provides technical guidance, energy bills assessments, and financial support. The Power Smart PAYS Financing Program enables community members to pay for the majority of the geothermal system through the energy savings that are realized by converting to a geothermal system. Through the partnership with AKI Energy, the program creates employment opportunities in First Nations communities. The initiative includes training and certification, funded by the participating communities, so that the installation and ongoing maintenance of the geothermal systems are completed by community members. To date, two First Nations communities have participated with 108 geothermal installations completed in 2013. The program will continue into 2014 with the goal of increasing the number of geothermal installs in the two current First Nations communities, and expanding to other First Nations communities.

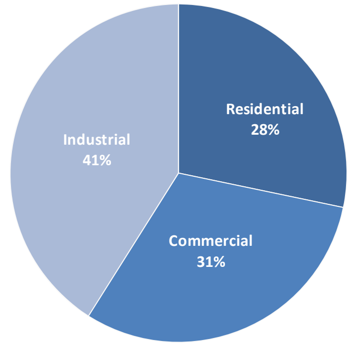
Residential Solar Domestic Water Heating

Water heating is the second largest energy consumer in a home next to space heating. Building upon the partnership with AKI Energy and to further reduce energy costs for customers living in First Nations communities, Manitoba Hydro is exploring opportunities with AKI Energy for solar domestic water heating in First Nations communities. With AKI Energy's commitment to sustainability and energy efficiency, this is an opportune time for Manitoba Hydro to explore a similar community-based pilot initiative for solar domestic water heating.

Electric DSM

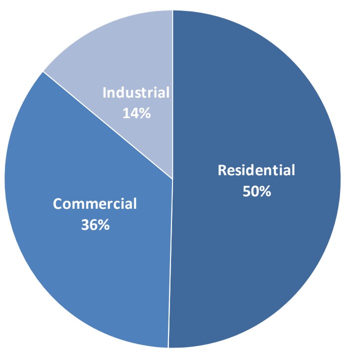
- Targeted electric savings of 411 MW and 1064 GW.h over the next 3 years.
- This activity represents 4.0% of the estimated load forecast by 2016/17.
- Combined with savings achieved to date, total electrical savings of 905 MW and 3,358 GW.h are expected to be achieved to 2016/17.
- These energy savings are equivalent to approximately 75% of the firm generation capability of Conawapa Generation Station or 1/2 of the electrical energy needs of Winnipeg (excluding industrial customers).

Electric Energy Savings
(cumulative to 2016/17)



Natural Gas DSM

Natural Gas Energy Savings
(cumulative to 2016/17)

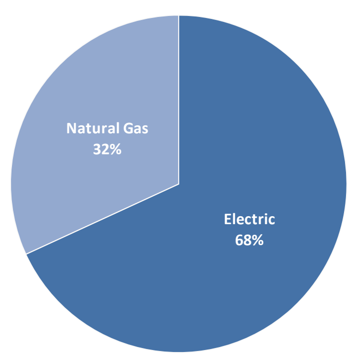


- Targeted natural gas savings of 32 million cubic meters over the next 3 years.
- This activity represents 1.6% of the estimated load forecast by 2016/17.
- Combined with savings achieved to date, total natural gas savings of 133 million cubic meters are expected to be achieved to 2016/17.
- These energy savings are equivalent to about 2 times the natural gas needs of Brandon (excluding industrial customers) or enough natural gas to serve over 56 000 homes.

Codes & Standards

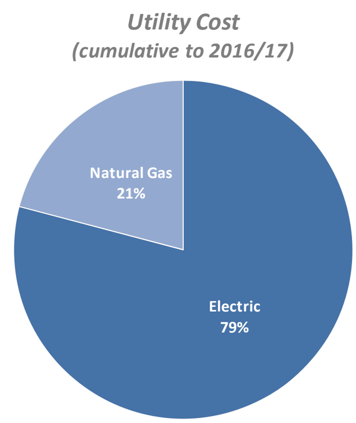
- Included in the DSM targets are electric savings of 81 MW and 284 GW.h and natural gas savings of 11 million cubic meters over the next 3 years.
- These energy savings result from codes and standards currently in place along with new codes and standards in the areas of residential and commercial lighting and appliances which will come into effect over the next 3 years.
- Combined with past efforts, electric savings of 247 MW and 978 GW.h and natural gas savings of 27 million cubic meters are expected to be achieved by 2016/17.

Codes & Standards Energy Savings
(cumulative to 2016/17)



Investment in DSM

- Over the next 3 years, Manitoba Hydro will invest $194 million in Power Smart incentive-based programs with an expected cumulative utility investment of $586 million by 2016/17.
- Including other program support and contingency costs, Manitoba Hydro will invest $232 million in Power Smart initiatives, with an expected cumulative utility investment of $817 million by 2016/17.
- Including participating customer costs, an investment of $393 million (only incentive-based programs) is forecasted, with an expected total investment of $1.1 billion by 2016/17, equivalent to approximately 65% of the capital cost of the Wuskwatim Generation Station. Customer investments through codes and standards, financing services, and other Power Smart drivers have not been estimated.

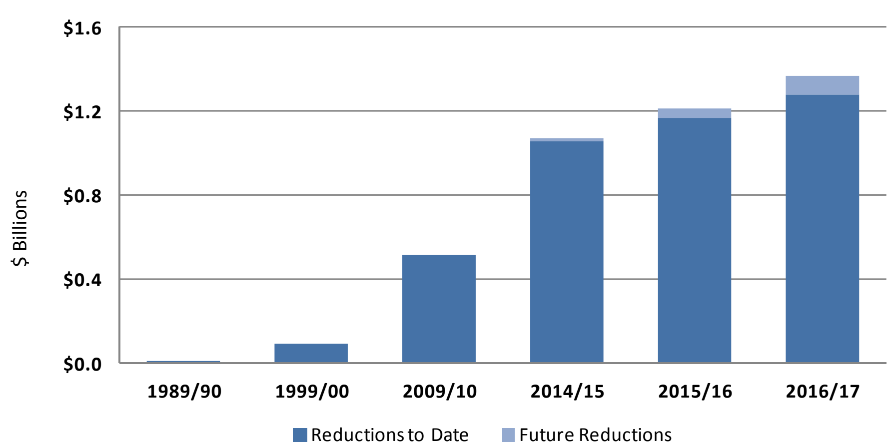


Greenhouse Gas Emission Reductions

- Targeted greenhouse gas emission reductions of 780,000 tonnes over the next 3 years.
- Including reductions achieved to date, 2.6 million tonnes are forecast to be achieved by 2016/17 which is equivalent to taking 520 000 cars off the road for one year.

Customer Bill Reductions

- Power Smart programs will save participating customers an additional $88 million in electricity and natural gas bills during 2016/17.
- Including bill reductions achieved to date, participating customers will save a cumulative $1.4 billion on electric and natural gas bills during 2016/17.



Contents

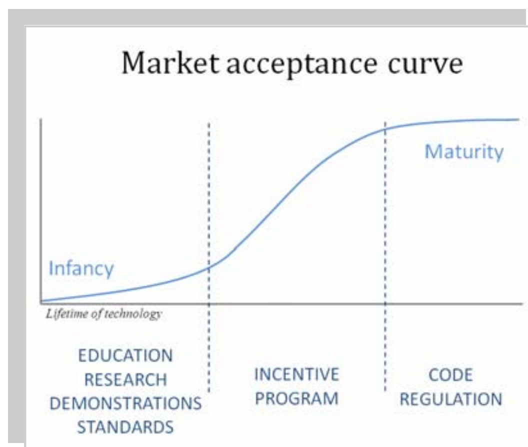
DSM Strategy

Manitoba Hydro's DSM strategy is to aggressively pursue all cost-effective energy efficiency opportunities and continually monitor the market to identify emerging trends and opportunities that may become viable and cost-effective DSM initiatives within the planning horizon.

Manitoba Hydro's DSM initiative, marketed under the Power Smart brand, is designed to encourage the efficient use of energy in residential, commercial, and industrial customer sectors. Manitoba Hydro's overall DSM strategy involves taking a broad approach to capturing energy efficiency opportunities: education to build awareness and understanding, creating foundations through the support of standards, motivating customers with the aid of financial tools, and entrenching energy savings through the support of federal and provincial codes and regulations.

In assessing options for pursing a DSM opportunity, Manitoba Hydro uses a number of metrics as guidelines to assess energy efficient opportunities. These metrics assist in determining whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options, and the relative investment sharing between ratepayers and participating customers. These metrics include the Total Resource Cost, Societal Cost, Rate Impact Measure, Levelized Utility Cost, and Customer Simple Payback. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

As outlined in the following graph, Manitoba Hydro takes a three stage approach to achieving market transformation. In the infancy stage of emerging opportunities, Manitoba Hydro supports these technologies by building customer awareness, demonstrations, and/or through investments in research and development. As market acceptance increases and the opportunity becomes cost-effective, financial incentives and/or other market intervention strategies are pursued to encourage customers to install the technology. As the product matures and market adoption grows, incentive-based programming generally becomes uneconomic. During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. This latter strategy also ensures permanent market transformation for the specific energy efficiency opportunity.



An Example: Changing Furnace Efficiencies in Manitoba

In 2001, only 30% of all natural gas furnaces being installed in Manitoba were high-efficient models and customer awareness of higher efficiency options was low. In response to this market situation, Manitoba Hydro launched the Power Smart Residential Loan and supporting Home Comfort and Energy Savings campaign to educate and promote the installation of high efficient natural gas furnaces. This approach laid the foundation for customers to consider the energy efficient alternative, and provided a tool for contractors to promote this technology.

In 2005, to further increase market acceptance, a $245 incentive was introduced to encourage customers to choose high efficient natural gas furnaces over the less efficient alternative. By 2007, high efficiency furnaces had grown to represent 76% of all furnaces being replaced in Manitoba homes. In 2008, to accelerate the number of customers upgrading their furnaces, Manitoba Hydro increased their rebate to $500 for a limited time offering and aggressively promoted the financial and comfort benefits of upgrading a furnace.

As market acceptance increased, Manitoba Hydro worked with the Province of Manitoba to develop the framework to regulate the minimum efficiency of all natural gas furnaces installed in Manitoba. On December 30, 2009, with market penetration of 86%, the Power Smart incentive ended and the Provincial regulation took effect requiring a minimum 92% AFUE for natural gas furnaces installed in Manitoba.

Power Smart Plan

Manitoba Hydro's Power Smart Plan is a roadmap for the future direction of the Corporation's energy conservation program. It was developed through an intensive planning process that builds on the Corporation's experience and continuous involvement in energy conservation since 1989. The Power Smart portfolio offers programs and initiatives to pursue opportunities in all market sectors; residential, commercial, and industrial. These programs are designed based on an in-depth knowledge of the technology and the market environment. An in-depth understanding is essential to ensure that the program design is adequately and effectively addressing the appropriate target market and contains the tools and strategies to address market barriers.

The following table outlines the forecasted achievements of this 3-year plan.

	1989/90 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Capacity Savings (MW)	494.6	242.5	319.4	410.5	**905.1**
Energy Savings (GW.h)	2,294.0	362.7	660.4	1,063.9	**3,357.9**
Natural Gas Savings (million m^3)	100.9	10.2	21.1	32.2	**133.1**
Utility Investment (Millions, 2014$)	$584.6	$69.6	$75.8	$86.6	**$816.5**
Customer Investment (Millions, 2014$)	$161.8	$34.0	$48.8	$78.5	**$323.1**
Total DSM Investment (Millions, 2014$)	$746.4	$103.5	$124.7	$165.1	**$1,139.7**

**Includes estimates for 2013/14*

Residential

Manitoba Hydro offers a number of incentive-based and financial support programs to address opportunities in the residential market.

Incentive-Based Programs

Home Insulation Program

The Home Insulation Program was launched in May 2004 and is scheduled to run until March 31, 2027. The program was designed to encourage homeowners to upgrade insulation levels and air sealing in their homes' attics, walls, and foundations. Upgrading insulation offers significant energy savings, reduces customers' monthly utility bills, and provides a more comfortable living space.

The program targets existing electric and natural gas heated homes with fair or poor insulation levels; approximately 35 000 electric homes and 129 000 natural gas homes were identified as the overall target market for the program (excluding homes targeted by the Affordable Energy Program). The program has been designed to address barriers to the adoption of energy efficient insulation including the lack of customer awareness regarding the financial and comfort benefits of increased insulation levels, the upfront capital cost of the upgrade, and the lack of priority when compared to more aesthetic and visible renovation projects. These market barriers are addressed through a comprehensive strategy that includes financial incentives to reduce the material cost of the upgrade, informational materials in the form of advertising campaigns, renovation "how to" booklets that provide technical guidance for upgrading insulation to Power Smart levels, and in-home energy evaluations to identify the highest potential energy efficiency upgrades. Power Smart on-bill financing programs are also promoted to provide additional encouragement for customers that are reluctant to consider allocating their renovation budget towards adding insulation to their home. Homeowners with technical barriers to upgrading insulation, such as finished basements, landscaping, and existing wall configurations, are encouraged to consider an upgrade as a component to an already planned renovation, for example, adding insulation to an exterior wall as part of a re-siding project.

To date, approximately 11 324 electric and 22 709 natural gas homes have undertaken insulation upgrades. The program is forecast to reach 73% of targeted electric customers and 34% of targeted natural gas customers by program end in 2026/27.

	2004/05 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Houses (annual)	34,033	2,664	2,521	2,384	**41,602**
Capacity Savings (MW)	27.3	2.9	5.5	7.8	**35.2**
Energy Savings (GW.h)	55.5	5.4	10.3	14.6	**70.1**
Natural Gas Savings (million m^3)	12.0	0.8	1.5	2.3	**14.2**
Utility Investment (Millions, 2014$)	$35.8	$3.5	$3.4	$3.2	**$45.9**
Customer Investment (Millions, 2014$)	$22.7	$1.1	$1.1	$1.0	**$25.8**
Total DSM Investment (Millions, 2014$)	$58.5	$4.6	$4.4	$4.2	**$71.7**

Estimated Average Annual Bill Reduction per Customer (Electric): $320

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $151

**Includes estimates for 2013/14*

Affordable Energy Program

The Affordable Energy Program (AEP) was launched in December 2007. The program's objective is to assist lower income homeowners in implementing energy efficiency upgrades, such as improved insulation, high efficiency natural gas furnaces, and various low cost measures. These upgrades can provide significant energy savings, decreasing the customer's monthly energy bills while increasing the comfort of their home. The criteria for determining program eligibility are the Low Income Cut-Off (LICO) thresholds set by Statistics Canada; customers' total household income must fall below 125% of the LICO thresholds for inclusion in the program. There are approximately 115 000 homes in Manitoba, excluding multi-unit residential buildings, that fall below the LICO 125% threshold; 105 000 of customers own their home, while 10 000 customers rent. The primary targets within this market are homes with poor or fair insulation levels and standard efficient furnaces. They make up 22% (25 298) and 18% (20 525) of the market, respectively.

The program was designed recognizing the unique barriers lower income customers face in completing energy efficiency retrofits. Manitoba Hydro assists and encourages participation in this market by minimizing the financial burden with free insulation upgrades and provision of a low cost high efficiency natural gas furnace replacement, along with free low cost items (e.g. CFLs, caulking, faucet aerators). To further encourage participation, the furnace copayment was reduced to $9.50/month from $19, the boiler rebate was increased to $3 000 from $2 500 and the program was expanded to landlords renting to lower income Manitobans. The program is delivered through a number of approaches including direct participation with individual customers or through community groups (e.g. First Nations', Neighbourhood communities, social enterprises). Through these approaches, customers are made aware of the value of energy efficiency retrofits, along with the benefits of participating in the program. Customers are targeted through advertising and community-based campaigns, customized information sessions, and community networks. A community-led initiative, the Neighbourhood Approach, began in fall 2012 with the goal of completing energy efficiency upgrades on a block-by-block basis in lower income neighbourhoods. Under this approach, North End Community Renewal Corporation and Brandon Neighbourhood Renewal Corporation employ local residents and social enterprises, Building Urban Industries for Local Development (BUILD), Brandon Energy Efficiency Program (BEEP) and Inner City Renovation, to bring energy efficiency upgrade opportunities direct to the customer's door.

To date, an estimated 8 072 energy efficiency retrofits have been completed. Of the total retrofits, 5 683 insulation projects have been completed and 3 009 furnaces have been replaced. The program is forecast to reach 66% (16 615) of the targeted homes with poor or fair insulation levels and 50% (10 301) of standard furnaces within the total LICO 125% market by 2026/27.

	2007/08 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Total Participation (annual)	8,072	2,155	2,180	2,093	**14,500**
No. of Insulation Projects (annual)	5,683	1,249	1,141	1,049	**9,122**
No. of Furnaces Installed (annual)	3,009	687	660	634	**4,990**
No. of Boilers Installed (annual)	75	15	15	15	**120**
Capacity Savings (MW)	6.8	2.1	4.1	6.0	**12.8**
Energy Savings (GW.h)	13.7	3.9	7.6	11.2	**24.9**
Natural Gas Savings (million m^3)	5.7	1.3	2.6	3.7	**9.4**
Utility Investment (Millions, 2014$)	$32.1	$7.4	$7.1	$4.7	**$51.2**
Customer Investment (Millions, 2014$)	$1.0	$2.4	$2.1	$1.8	**$7.4**
Total DSM Investment (Millions, 2014$)	$33.1	$9.8	$9.2	$6.6	**$58.7**

Estimated Average Annual Bill Reduction per Customer - Basic Measures (Electric): $93
Estimated Average Annual Bill Reduction per Customer - Basic Measures (Natural Gas): $25
Estimated Average Annual Bill Reduction per Customer (Electric) - Insulation: $582
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Insulation: $218
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Furnace: $231

**Includes estimates for 2013/14*

Water and Energy Saver Program

The Water and Energy Saver Program was launched in September 2010. Its primary objective is to reduce residential water heating energy consumption through the use of low flow, energy efficient plumbing fixtures. Customers are offered a free water and energy saver kit with program messaging focused on the energy and water benefits of energy efficient plumbing fixtures. The program offers three channels of participation: mail, targeted direct installation, and a bulk mail option for property managers of multi-unit residential facilities.

The target market includes all residential dwellings that use electricity or natural gas to heat water, totaling 515 000 customers. A lack of awareness of the benefits of energy efficient plumbing fixtures and, for some customers, a perception that their fixtures are already energy efficient, combined with limited availability of Power Smart qualifying products at local retailers, will limit customer adoption of the higher efficiency fixtures. Through advertising and the free kit offering, market acceptance of Power Smart plumbing fixtures will increase.

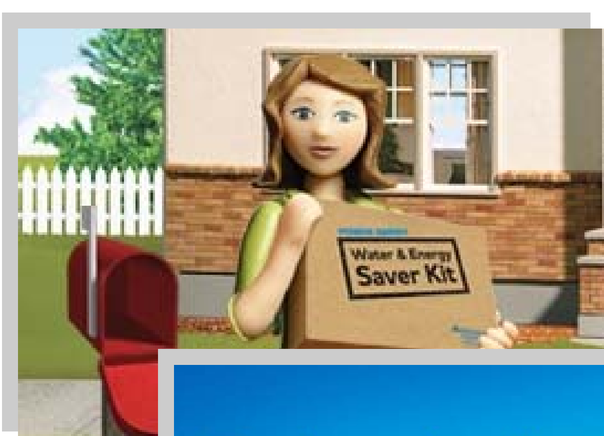
To date, over 120 000 residential dwellings have participated in the program. The program is on target to reach 40% of targeted homes by program end.

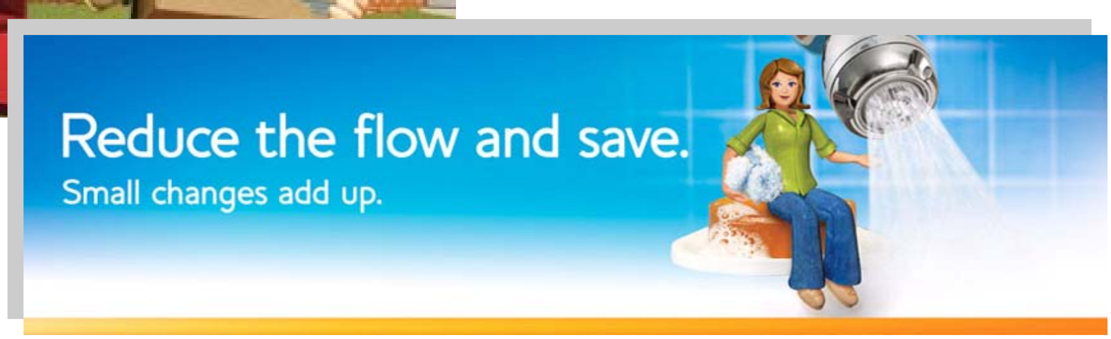
	2010/11 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Houses (annual)	121,367	28,798	28,798	28,798	**207,761**
Capacity Savings (MW)	2.4	0.7	1.3	2.0	**4.3**
Energy Savings (GW.h)	19.2	3.3	6.6	10.0	**29.2**
Natural Gas Savings (million m^3)	3.8	0.8	1.6	2.5	**6.3**
Utility Investment (Millions, 2014$)	$6.8	$1.8	$1.8	$1.8	**$12.3**
Customer Investment (Millions, 2014$)	$0.0	$0.0	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2014$)	$6.8	$1.8	$1.8	$1.8	**$12.3**

Estimated Average Annual Bill Reduction per Kit (Electric): $25

Estimated Average Annual Bill Reduction per Kit (Natural Gas): $14

**Includes estimates for 2013/14*





Refrigerator Retirement Program

The Refrigerator Retirement Program was launched in June 2011 and is extended by 3 more years ending in March 2017. The objective of the program is to reduce residential energy consumption through the removal of old, inefficient, and often nearly empty refrigerators and freezers. The program offers free in-home pickup of qualifying working units plus a $50 incentive for the last 3 years of the program.

The target market is residential homes representing approximately 224 000 older second fridges and 222 000 freezers. Customers can save over $100 per year in electricity costs by removing these units. The program encourages customers to retire their secondary appliance and not replace it in order to maximize savings.

Most customers do not know the costs of operating an underutilized refrigerator or freezer, and many lack assistance in removing the appliance from the home. Through the program, customers are made aware of the costs of their second appliance and the benefits of “retiring” it. The program makes “retiring” easy by providing an in-home pickup service.

To date, over 25 000 units have been retired. The program is forecast to retire 20% of these older fridges and 5% of these freezers by program end.

	2011/12 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Total Participation (annual)	25,715	11,000	11,000	9,000	**56,715**
No. of Fridges (annual)	21,675	8,000	8,000	7,000	**44,675**
No. of Freezers (annual)	4,040	3,000	3,000	2,000	**12,040**
Capacity Savings (MW)	3.5	1.4	2.8	4.0	**7.5**
Energy Savings (GW.h)	35.9	12.7	25.4	36.0	**71.8**
Utility Investment (Millions, 2014$)	$4.9	$2.3	$2.3	$2.0	**$11.5**
Customer Investment (Millions, 2014$)	$2.7	$1.6	$1.6	$1.3	**$7.1**
Total DSM Investment (Millions, 2014$)	$7.6	$3.9	$3.8	$3.2	**$18.6**

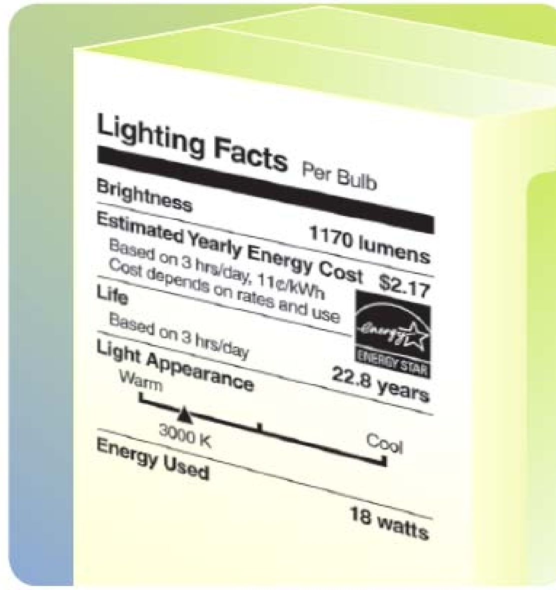
Estimated Average Annual Bill Reduction per Customer (Electric) without fridge replacement: $100

Estimated Average Annual Bill Reduction per Customer (Electric) without freezer replacement: $70

**Includes estimates for 2013/14*

Residential LED Lighting Program

The Residential LED Lighting Program is a proposed 5-year program designed to encourage residential customers to choose the most energy efficient lighting technology for each application within their home. The program will aim directly at increasing market adoption of Light Emitting Diode (LED) technologies as a replacement for incandescent and halogen screw-in light bulbs.



The target market includes 530 000 residential dwellings and nearly 17 million screw-based sockets in which LED and other energy efficient lamps can be used. Although consumers are slowly moving toward replacing existing incandescent and halogen bulbs with LEDs as LED prices continue to decrease, the lack of awareness of the benefits and available variety of LED products remain significant barriers to widespread adoption. The program will employ a comprehensive communication strategy including traditional and new media, presence at a number of key events, and a buy-one-get-one retail rebate campaign in the fall 2014. Savings will be determined by conducting a thorough analysis of data including retail sales, product shelf space, customer surveys, and comparisons between Manitoba and other markets. The program is expected to increase sales of screw-in LED bulbs in Manitoba by approximately 13% during the course of the campaign.

	2014/15	2015/16	2016/17	Total to 2016/17
No. of Bulbs (annual)	59,939	11,750	56,085	**127,774**
Capacity Savings (MW)	0.6	0.7	1.1	**1.1**
Energy Savings (GW.h)	2.6	2.9	4.4	**4.4**
Utility Investment (Millions, 2014$)	$1.0	$0.2	$0.2	**$1.5**
Customer Investment (Millions, 2014$)	$0.1	$0.0	$0.1	**$0.2**
Total DSM Investment (Millions, 2014$)	$1.1	$0.3	$0.4	**$1.7**
Estimated Average Annual Bill Reduction per Bulb (Electric): $3				

Residential Community Geothermal Program

The Residential Community Geothermal Program aims to reduce customers' electric space heating costs through the adoption of geothermal heat pump systems in First Nations communities. The program is designed to offer a customized approach for each community, with the assistance of AKI Energy, a non-profit social enterprise group. To help mitigate the high capital cost barrier, a third-party provider is contracted to conduct a feasibility study and to provide a quote on the bulk purchase of the heat pump units, including installation, resulting in a much lower per unit price than the current market average. Another component of the program includes creating job opportunities and training Band members to take part in the installation and the ongoing maintenance of the geothermal systems. The training is funded by the First Nations themselves. Manitoba Hydro provides technical guidance, assesses the energy bills to determine which homes would be the most suitable for economic geothermal installations, and explores opportunities to further maximize the number of geothermal installations. Manitoba Hydro's PAYS Financing Program is utilized to enable community members to pay for the majority of the geothermal system through the energy savings that are realized by converting their heating/air conditioning systems to a geothermal system. For those homes that will not realize enough energy savings to finance the entire cost of the system, Manitoba Hydro or the Band will buy down the remaining cost in order to ensure that their energy bill does not change post-installation.

It is anticipated that the Residential Community Geothermal Program will increase the adoption of heat pumps in First Nations communities as the total cost of the system will be substantially reduced and the loan will be paid through the energy savings.

	2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Geothermal Systems (annual)	101	300	425	500	**1,326**
Capacity Savings (MW)	0.4	1.2	2.9	5.0	**5.4**
Energy Savings (GW.h)	1.6	4.6	11.1	18.8	**20.4**
Utility Investment (Millions, 2014$)	$0.4	$1.6	$2.0	$2.4	**$6.3**
Customer Investment (Millions, 2014$)	$0.0	$3.1	$4.4	$5.2	**$12.8**
Total DSM Investment (Millions, 2014$)	$0.4	$4.7	$6.5	$7.6	**$19.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $1,005					

**Includes estimates for 2013/14*

Support Programs

Manitoba Hydro offers the following convenient financing programs to support the incentive-based programs by allowing customers to finance initial Power Smart project costs and pay the costs back on their monthly Manitoba Hydro bill.

Power Smart Residential Loan

The Power Smart Residential Loan (PSRL) was launched in March 2001 to provide customers with convenient on-bill financing to assist them in making their home more energy efficient. Under the PSRL, the following energy efficiency improvements can be made to the home: insulation, ventilation equipment, air leakage sealing, windows and doors, and space and water heating equipment.

The target market consists of all electric and natural gas customers in Manitoba. Participants can borrow up to $7 500 ($5 500 for natural gas furnaces) and repay the amount on their energy bill over a term of up to 5 years (up to 15 years for natural gas furnaces and boilers).

	2001/02 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Loans (annual)	75,858	6,000	6,000	6,000	**93,858**
Capacity Savings (MW)	5.6	0.3	0.6	0.9	**6.5**
Energy Savings (GW.h)	10.1	0.6	1.1	1.7	**11.8**
Natural Gas Savings (million m^3)	15.2	0.3	0.6	0.9	**16.1**
Average Loan Amount: $4,666					

**Includes estimates for 2013/14*

Power Smart PAYS Financing

Power Smart PAYS (Pay As You Save) Financing was launched in November 2012. The PAYS Program offers low interest on-bill financing over a term of up to 25 years, depending upon the technology financed, with a fixed interest rate for up to 5 years. Energy efficient upgrades that may qualify for financing are:

- Space heating equipment:
  - High efficiency natural gas furnaces;
  - Natural gas boilers (minimum AFUE of 85%);
  - Electric furnaces, boilers or electric baseboard heat when it is the primary heating source;
  - Geothermal heat pump systems;
- Insulation upgrades;
- Drainwater heat recovery systems;
- WaterSense toilets (in conjunction with energy efficient equipment).

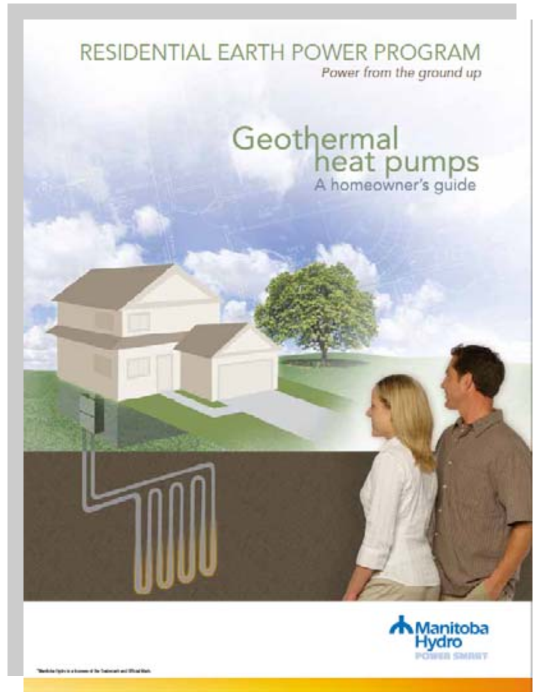
The target market consists of all electric and natural gas customers in Manitoba. This offering complements and supports existing incentive-based programs by assisting customers in managing the installation cost of their upgrade. To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing payment, thereby resulting in an energy bill that is less than or equal to the total bill prior to the retrofit. PAYS financing also differs from Manitoba Hydro's other financing programs in that the loan is transferable between homeowners when a property is sold, and is transferable from a landlord to a tenant where the tenant is responsible for paying the energy bill.

	2012/13 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Loans (annual)	295	553	811	1,157	**2,816**
Capacity Savings (MW)	0.1	0.1	0.3	0.4	**0.5**
Energy Savings (GW.h)	0.4	0.5	0.9	1.4	**1.7**
Natural Gas Savings (million m^3)	0.0	0.0	0.0	0.0	**0.0**
Average Loan Amount: $6,930					

**Includes estimates for 2013/14*

Residential Earth Power Loan

The Residential Earth Power Loan (REPL) was launched in April 2002 to support the adoption of geothermal heat pump technology. Although more expensive to install, geothermal heat pump systems offer significant electricity savings, thereby reducing customers' monthly utility bills. The convenience and flexibility of the on-bill REPL reduces the financial barrier that exists when installing a geothermal heat pump system. The program was also designed to build awareness of emerging technologies and foster new, growing industries that utilize these technologies through educational materials, technical support, and training workshops. Solar hot water systems were added as an eligible technology in 2010.



Customers are eligible for up to $20 000 in financing for installing geothermal heat pump systems or $7 500 in financing for installing solar domestic water heating systems. The financial terms include a 5-year fixed interest rate over a 15-year maximum amortization term. The interest rate for the balance of the financing period is established at Manitoba Hydro's cost of borrowing at the time the fixed interest rate term expires.

	2002/03 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Loans (annual)	1,237	26	26	27	**1,316**
Capacity Savings (MW)	4.4	0.3	0.6	1.0	**5.4**
Energy Savings (GW.h)	14.8	1.3	2.6	4.1	**18.9**
Natural Gas Savings (million m^3)	2.4	0.2	0.4	0.6	**3.0**
Average Loan Amount: $18,728					

**Includes estimates for 2013/14*

Commercial

Manitoba Hydro offers a number of incentive-based programs and one financial support program to address opportunities in the commercial market.

Incentive-Based Programs

Commercial Lighting Program

The Commercial Lighting Program was launched in May 1992 to reduce electricity consumption by accelerating the acceptance and adoption of energy efficient lighting technologies in Manitoba. Commercial, industrial, and agricultural customers are encouraged to install qualifying energy efficient lighting technologies in their facilities to reduce energy bills, improve the quality of lighting, as well as increase safety, security, and productivity. The program offers support through the use of educational materials, information seminars, and financial incentives.

The target market consists of all existing commercial, industrial, and agricultural buildings with inefficient lighting installations in Manitoba, where lighting systems operate a minimum of 2 000 hours per year. New construction projects that do not meet the New Buildings Program Eligibility Criteria may qualify. The estimated market size is 52 500 lighting projects. Many energy efficient lighting options have higher initial capital costs, and often customers lack awareness of the technologies available and the non-energy related benefits of energy efficient lighting, thereby creating a barrier to the adoption of higher efficiency systems. In addition, many customers operate in commercial lease space where the person making decisions related to lighting upgrades may not pay the utility bill and therefore, does not realize the direct financial return. Strategies in place to address these market barriers include financial incentives, education and training, as well as hands on technical and customer service support.

To date, over 13 000 energy efficient lighting projects have been completed. The program is forecast to reach 30% of the target market by the end of 2016/17.

	1992/93 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	13,183	820	860	869	**15,732**
Capacity Savings (MW)	71.2	10.4	21.3	31.5	**102.7**
Energy Savings (GW.h)	389.6	37.4	76.6	113.4	**503.0**
Utility Investment (Millions, 2014$)	$95.4	$8.6	$8.7	$8.4	**$121.1**
Customer Investment (Millions, 2014$)	$37.6	$4.8	$4.9	$5.4	**$52.6**
Total DSM Investment (Millions, 2014$)	$132.9	$13.4	$13.6	$13.7	**$173.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $264					

**Includes estimates for 2013/14*

LED Roadway Lighting Conversion Program

The LED Roadway Lighting Conversion Program (RLP) will retrofit existing High Pressure Sodium (HPS) roadway lights to Light Emitting Diode (LED) over a 7-year period. Manitoba Hydro provides energy and maintenance services to over 130 000 roadway lights across the Province of Manitoba. The cities or rural municipalities where the lighting is located, pay Manitoba Hydro a monthly rate per fixture, that includes installation costs, estimated energy consumption, and maintenance charges. The monthly rate charged has been approved through the Manitoba Public Utilities Board (PUB).

The current roadway lighting technology is High Pressure Sodium (HPS), which produces a yellow/orange light and has a 5-year lamp life. The wattages range from 70 to 1 000 and were originally installed in 1991 under a past Power Smart Roadway Lighting Conversion Program to replace Mercury Vapour and Incandescent lighting.

Converting existing roadway lighting to LED will result in energy and maintenance savings that will be factored into a new monthly rate subject to PUB approval. Under the recommended conversion program, there will be no initial cost to the city/municipality for the LED lighting retrofit. Manitoba Hydro will be using a partial cost recovery model under which the current HPS rates would be held for a period of 10 years after installation, allowing the corporation to recoup a portion of its investment through the rate differential.

	2014/15	2015/16	2016/17	Total to 2016/17
No. of Conversions (annual)	18,591	18,150	16,138	**52,879**
Capacity Savings (MW)	0.8	1.7	2.4	**2.4**
Energy Savings (GW.h)	5.8	11.4	16.4	**16.4**
Utility Investment (Millions, 2014$)	$6.2	$6.1	$5.2	**$17.4**
Customer Investment (Millions, 2014$)	$0.0	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2014$)	$6.2	$6.1	$5.2	**$17.4**

Commercial Building Envelope - Windows Program

The Commercial Building Envelope (Windows) Program has been promoting the benefits of energy efficient windows to commercial customers since 1995. The program's primary objective is to improve building envelope performance and reduce energy consumption through the installation of high performance windows in existing buildings.

The target market consists of all existing commercial customers, primarily focused on sectors such as multi-unit residential facilities, schools, hotels/motels, personal care homes, and health care facilities. The program targets facilities planning to replace existing windows, thus presenting an economic opportunity to install higher efficiency Power Smart qualifying windows at the time of replacement.

Market barriers include the incremental product cost of high performance windows, along with a lack of awareness of the significant potential energy savings and other non-energy benefits. Providing financial incentives to help offset incremental material costs, working closely with local fabricators and window suppliers and contractors, while promoting the benefits of high performance windows is effectively addressing these barriers.

To capture the potential energy savings outlined in the recent DSM Potential Study that was completed in 2013, the program is committed to extend its incentive offerings to the end of the 2028/29 fiscal year. In response to changes in window pricing over the past couple of years and to encourage the installation of higher performance window systems, incentives for window upgrades have been revised.

In addition to the revised incentives to the existing program, Manitoba Hydro recognizes that the heavy commercial market, comprised of commercial buildings with curtain wall facades, do not qualify within the current program aimed at buildings with punched window configurations, and remains a market that is difficult to reach. The nature of the on-site construction of curtain wall assemblies, as well as the much greater incremental cost associated with upgrading in existing buildings, is the largest barrier to the program. Thus, the program is offering a new curtain wall financial incentive to assist customers that fall in this category, to upgrade the performance of their existing curtain wall assemblies when the time comes. This incentive will be available to customers with electrically-heated buildings.

It is estimated that there are approximately 750 potential window replacement projects in Manitoba each year, of a total market of 27 000 potential projects. To date, over 1 300 energy efficient window projects have been completed. The program is forecast to reach 8% of the target market by the end of 2016/17.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	1,326	234	237	240	**2,037**
Capacity Savings (MW)	6.9	1.1	2.1	3.1	**10.0**
Energy Savings (GW.h)	17.1	2.8	5.4	7.7	**24.8**
Natural Gas Savings (million m^3)	1.9	0.4	0.7	1.0	**2.9**
Utility Investment (Millions, 2014$)	$13.7	$1.8	$1.4	$1.1	**$18.1**
Customer Investment (Millions, 2014$)	$0.1	$0.4	$0.5	$0.5	**$1.5**
Total DSM Investment (Millions, 2014$)	$13.8	$2.3	$1.9	$1.6	**$19.6**

Estimated Average Annual Bill Reduction per Customer (Electric): $895

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $643

**Includes estimates for 2013/14*

Commercial Building Envelope - Insulation Program

The Commercial Building Envelope (Insulation) Program was launched in April 2006. Its primary objective is to improve building envelope performance and reduce energy consumption by upgrading insulation levels in roof and wall areas of existing buildings.

The target market is comprised of all commercial customers with insulation levels that do not meet Power Smart levels. The program targets facilities planning to undergo extensive repairs to existing roofs and walls, presenting an economic opportunity to improve existing insulation levels at the time of renovation.

Market barriers include the incremental product cost of insulation upgrades and a lack of awareness of the significant potential energy savings and other non-energy benefits associated with upgraded insulation levels. Providing financial incentives to help offset incremental material costs and promoting the benefits of better insulated buildings is effectively addressing these barriers.

It is estimated that there are approximately 400 potential insulation replacement projects in Manitoba each year, of a total market of 15 000 potential projects. To date, over 1 300 insulation projects have been completed. The program is forecast to reach 15% of the target market by the end of 2016/17.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	1,336	308	313	316	**2,273**
Capacity Savings (MW)	12.5	1.1	2.2	3.0	**15.6**
Energy Savings (GW.h)	25.0	2.8	5.5	7.7	**32.7**
Natural Gas Savings (million m^3)	9.0	0.9	1.8	2.6	**11.7**
Utility Investment (Millions, 2014$)	$13.5	$2.5	$2.5	$2.2	**$20.6**
Customer Investment (Millions, 2014$)	$8.2	$0.6	$0.6	$0.5	**$9.9**
Total DSM Investment (Millions, 2014$)	$21.8	$3.1	$3.1	$2.7	**$30.5**

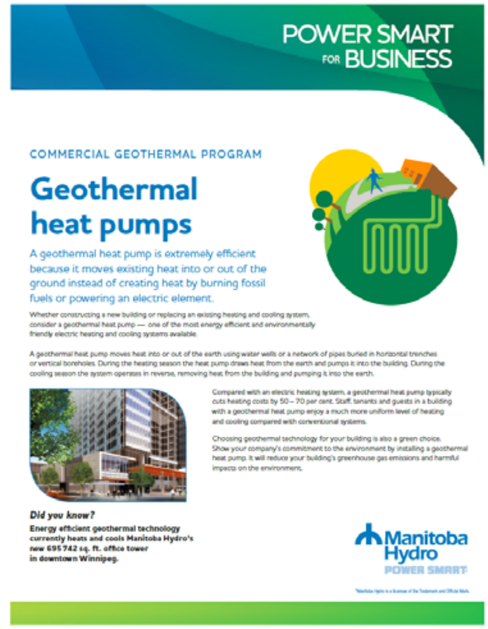
Estimated Average Annual Bill Reduction per Customer (Electric): $145

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $197

**Includes estimates for 2013/14*

Commercial Geothermal Program

The Commercial Geothermal Program was launched in 2007 with the primary objective to encourage the installation of geothermal heat pumps in electrically-heated commercial buildings.



The target market consists of new and existing commercial buildings that use conventional electric technologies for space heating. There are approximately 6 084 existing electrically heated facilities using more than 30 000 kW.h per year in Manitoba. There are approximately 200 new commercial buildings constructed each year of which approximately 10% are located in electric heat only territory. It is assumed 243 existing buildings will replace their electric heating systems and 20 new buildings in electric heat only territory will be constructed for a total of 263 potential participants annually. The high capital cost of installing a geothermal heat pump system, combined with the available supply of qualified installers and contractors in some regions of the province; challenging drilling and trenching conditions due to varying geological conditions; limited land area of many properties to accommodate the loop installation; and the proximity to the ground loop of underground facilities and services (water and sewer lines that may freeze, etc.) can make choosing geothermal as a heating/cooling option more challenging for the customer. Through the program, customers are provided with information on how the geothermal heat pump technology works, the energy savings available, and other benefits to increase understanding and acceptance of the technology. Financial incentives are offered to help offset the higher capital costs of the system at a rate of $3.50 per square foot of floor area heated by geothermal or $171 per MBH (thousands of BTUs per hour) of installed geothermal space heating capacity. Incentives are also available to support feasibility studies to ensure the project meets the heating and cooling needs of the building while achieving the necessary electrical savings that make installing a geothermal heat pump an economic option for the customer. Benefits of geothermal systems and program opportunities are communicated through the broad network of engineers, architects, consultants, contractors, and trade allies in Manitoba who have established relationships with the commercial and industrial customer base.

To date, approximately 131 commercial buildings have installed geothermal systems. The program is forecast to achieve 50% of annual heating systems upgrades being geothermal by 2028/29.

	2007/08 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Buildings (annual)	131	33	39	47	**250**
Capacity Savings (MW)	14.7	0.4	1.4	2.7	**17.4**
Energy Savings (GW.h)	35.4	1.8	6.0	11.1	**46.5**
Utility Investment (Millions, 2014$)	$5.7	$1.0	$2.0	$2.4	**$11.1**
Customer Investment (Millions, 2014$)	$17.7	$0.4	$0.9	$1.1	**$20.0**
Total DSM Investment (Millions, 2014$)	$23.4	$1.4	$2.9	$3.4	**$31.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $5,145					

**Includes estimates for 2013/14*

Commercial HVAC Program - Boilers

The Commercial HVAC Program for Boilers is a 10-year program launched in April 2006. The program's primary objective is to transform the commercial boiler market in Manitoba by increasing awareness and adoption of energy efficient condensing and near-condensing boilers. Energy efficient boilers offer significant natural gas savings, reducing customers' monthly utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives ranging from $2/MBH (thousands of BTUs per hour) to $8/MBH are provided for qualifying systems.

The program is designed to build market acceptance prior to, thereby ensuring the successful adoption of, Natural Resources Canada's (NRCan) minimum efficiency regulations for commercial boilers, which are currently under development.

The primary target market consists of commercial buildings with existing heating equipment at or approaching end of life. On average, 282 commercial boilers are installed annually in existing buildings. Boiler replacements are not likely to occur until existing equipment is near the end of its life and are often completed in an emergency situation during the heating season. Therefore, purchase decisions are made with limited lead time and primarily based on the initial capital cost, not considering the annual operating costs of the system over its 25-year life. Condensing or near-condensing natural gas boilers are also more expensive to install than conventional boilers, and require modifications to the ventilation system. Financial incentives combined with information on the lifecycle cost-advantage of energy efficient systems are in place to address these market barriers.

The program is forecast to achieve 42% of the target market being energy efficient by the planned program end date of March 31, 2016. The program will pursue provincial regulations requiring all boilers installed in new buildings in Manitoba to be condensing by April 1, 2016.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Boilers (annual)	929	126	133	0	**1,188**
Natural Gas Savings (million m^3)	9.2	1.0	2.1	2.3	**11.5**
Utility Investment (Millions, 2014$)	$9.7	$1.1	$1.2	$0.0	**$12.0**
Customer Investment (Millions, 2014$)	$6.6	$0.6	$0.4	$0.2	**$7.8**
Total DSM Investment (Millions, 2014$)	$16.3	$1.7	$1.6	$0.2	**$19.8**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $2,088					

**Includes estimates for 2013/14*

Commercial HVAC Program - Chillers

The Commercial HVAC Program for Chillers is a 16-year program launched in April 2006. Its primary objective is to transform the commercial chiller market in Manitoba by increasing awareness and adoption of energy efficient water-cooled chillers and variable speed drive retrofits. Energy efficient chillers offer significant electricity savings, reducing customers' utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives of $72 per ton are provided for qualifying units.

The primary target market for chillers are large, older, commercial buildings, consisting primarily of large offices, large multi-residentials, hospitals, and large educational facilities. The high initial cost of chiller systems combined with the tendency for customers to emphasize the initial investment cost over operating efficiency or lifecycle costs when making their purchase decision, has created a barrier for the higher efficiency systems. Offering aggressive financial incentives while promoting the lifecycle cost-advantage is effectively addressing these barriers and ensuring that efficient chillers are chosen at the time of existing equipment replacement.

Typically, chillers have a 30-year life and are replaced when the refrigerant is required to be changed or when the equipment is reaching the end of its life. On average, 14 chillers, representing approximately 4 300 tons of cooling capacity, are replaced annually. The program is forecast to achieve 66% of chiller sales being energy efficient by the end of 2016/17.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Chillers (annual)	70	10	10	11	**101**
Capacity Savings (MW)	0.0	0.0	0.0	0.0	**0.0**
Energy Savings (GW.h)	12.2	2.5	4.0	5.6	**17.7**
Utility Investment (Millions, 2014$)	$1.9	$0.3	$0.3	$0.3	**$2.8**
Customer Investment (Millions, 2014$)	$2.0	$0.1	$0.1	$0.2	**$2.4**
Total DSM Investment (Millions, 2014$)	$3.8	$0.5	$0.4	$0.5	**$5.2**
Estimated Average Annual Bill Reduction per Customer (Electric): $11,400					

**Includes estimates for 2013/14*

Commercial HVAC Program - CO_2 Sensors

The Commercial HVAC Program for CO_2 Sensors is a 15-year program launched in April 2009. Its primary objective is to increase the awareness and adoption of CO_2 sensors in commercial facilities. CO_2 sensors reduce energy consumption by matching ventilation supply to occupant demand, thereby reducing customers' monthly utility bills. CO_2 sensors also improve occupant comfort by providing more consistent air quality and can extend the life of heating and cooling equipment by putting less demand on these systems.

The target market for CO_2 sensors consists of over-ventilated commercial facilities with variable occupancy and that have, or are considering installing, Direct Digital Control systems or rooftop units to control heating, cooling, and ventilation. Installations typically occur when other major renovations are being made to the ventilation system. It is estimated that a total of 277 potential sensor installations in Manitoba exist each year.

CO_2 sensors are not required in commercial building operation and therefore are often one of the first retrofit measures to be discarded in the event of budgetary constraints. Customers also tend to be unfamiliar with the operation of their ventilation systems and may be unaware of when a building is over-ventilated. Offering aggressive financial incentives combined with the promotion of the lifecycle cost-advantage and improved ventilation benefits, is effectively addressing these barriers.

	2009/10 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Sensors (annual)	241	152	199	238	**830**
Capacity Savings (MW)	0.0	0.1	0.2	0.3	**0.3**
Energy Savings (GW.h)	0.3	0.1	0.2	0.4	**0.7**
Natural Gas Savings (million m^3)	0.8	0.1	0.3	0.5	**1.3**
Utility Investment (Millions, 2014$)	$0.1	$0.2	$0.2	$0.2	**$0.6**
Customer Investment (Millions, 2014$)	$0.2	$0.0	$0.0	$0.0	**$0.3**
Total DSM Investment (Millions, 2014$)	$0.3	$0.2	$0.2	$0.2	**$1.0**

Estimated Average Annual Bill Reduction per Customer (Electric): $40

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $463

**Includes estimates for 2013/14*

Commercial HVAC Program - Water Heaters

The Commercial HVAC Program for Water Heaters is a 10-year program to be launched in April 2015. The program's primary objective is to advance transformation of the commercial water heater market in Manitoba prior to federal regulations taking effect by increasing awareness and adoption of energy efficient condensing water heaters. Domestic water heating typically represents 11% of a commercial building's energy consumption, but can be as high as 40% for high-use sectors such as car washes and laundromats. Upgrading to a condensing water heater can reduce water heating energy use by up to 28%. The program will focus on educating building owners and operators about the benefits of energy efficient equipment and will work with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives will average $3.90/MBH (thousands of BTUs per hour) for storage water heaters or $2.35/MBH for qualifying tankless water heaters.

The program is designed to build market acceptance prior to, and thereby ensuring the successful adoption of, Natural Resources Canada's (NRCan) minimum efficiency regulations for commercial water heaters, which are currently under development.

The primary target market consists of commercial buildings with high levels of water usage with existing water heating equipment at or approaching end of life. On average, 286 commercial water heaters are installed annually in existing buildings. Water heater replacements most often only occur when existing equipment is near its end of life and are often completed in an emergency situation. Purchase decisions are therefore made with limited lead time and primarily based upon the initial capital cost, not considering the annual operating costs of the system over the product lifecycle. Condensing water heaters are also more expensive to install than conventional water heaters because they typically require modifications to the ventilation system. Financial incentives combined with information on the lifecycle cost advantage of energy efficient systems will be put in place to address these market barriers.

The program is forecast to achieve 80% of annual water heater sales being energy efficient in the final year of the program. The program will pursue provincial regulations requiring all water heaters, including tankless systems, installed in new buildings within Manitoba to be condensing by April 1, 2025.

	2014/15	2015/16	2016/17	Total to 2016/17
No. of Water Heaters (annual)	0	19	31	**50**
Natural Gas Savings (million m^3)	0.0	0.0	0.1	**0.1**
Utility Investment (Millions, 2014$)	$0.0	$0.1	$0.1	**$0.2**
Customer Investment (Millions, 2014$)	$0.0	$0.1	$0.1	**$0.1**
Total DSM Investment (Millions, 2014$)	$0.0	$0.1	$0.2	**$0.3**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $207				

Commercial Custom Measures Program

The Commercial Custom Measures Program was launched in 2006 to encourage commercial customers to explore and implement energy efficient upgrades to their operations or facilities. This program offers the opportunity to explore customer-specific and unique projects or newer technologies that are not currently eligible under the other Power Smart for Business Program offerings. Technologies and projects may include digital control systems, hot water and space heating equipment, waste energy recovery systems, variable speed drive systems, and solar air and water heating systems. The program provides incentives to help cover the cost of feasibility studies that are often required for larger projects and newer or emerging technologies, and implementation incentives based on projected savings from the project.

The program targets all commercial customers planning new construction, renovation or expansion projects. Often the high incremental cost of energy efficient technologies and systems, customer uncertainty of payback, and lack of awareness of energy efficient alternatives limit a customer's propensity to invest in an energy efficient project. The Commercial Custom Measures Program addresses these barriers by promoting new and innovative technologies, offering a feasibility study incentive to provide confidence in energy savings estimates, and offering incentives to help reduce the implementation cost.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	78	14	15	15	**122**
Capacity Savings (MW)	1.9	0.3	0.6	0.9	**2.8**
Energy Savings (GW.h)	25.4	1.1	2.2	3.4	**28.7**
Natural Gas Savings (million m^3)	1.4	0.1	0.2	0.3	**1.7**
Utility Investment (Millions, 2014$)	$4.4	$0.6	$0.7	$0.7	**$6.4**
Customer Investment (Millions, 2014$)	$12.6	$0.6	$0.6	$0.6	**$14.3**
Total DSM Investment (Millions, 2014$)	$16.9	$1.2	$1.2	$1.3	**$20.6**
Estimated Average Annual Bill Reduction per Customer (Electric): $4,646					
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $6,427					

**Includes estimates for 2013/14*

Commercial Building Optimization Program

The Commercial Building Optimization Program (CBOP) was launched in 2006 to encourage commercial customers with existing buildings to engage in an assessment and adjustment process known as retrocommissioning (RCx) to help return their buildings' mechanical systems to their designed operating characteristics and even further optimize their operation to save energy and improve occupant comfort. The program focuses on identifying non-capital intensive energy conservation opportunities with relatively short payback periods and offers incentives that cover a portion of the cost of hiring an RCx agent and implementing the energy efficient measures identified through the investigation process.

The market consists of existing commercial buildings larger than 50 000 square feet and between 2 to 25 years of age with direct digital control systems and functioning heating, ventilating, and air conditioning mechanical systems. There are approximately 470 buildings in this market, however, there are significant barriers that must be overcome to reach these customers including the lack of experience and availability of RCx providers in Manitoba, lack of customer awareness of the cost-saving benefits of RCx, and lack of customer time and competing priorities for capital to invest in energy efficiency projects. The program addresses these barriers by providing training and information sessions for potential and existing RCx providers, promoting RCx at relevant industry events, and offering incentives to reduce the capital cost and payback cycle of the RCx process.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Buildings (annual)	15	4	4	6	**29**
Capacity Savings (MW)	0.0	0.1	0.2	0.4	**0.5**
Energy Savings (GW.h)	5.2	0.6	1.2	2.1	**7.3**
Natural Gas Savings (million m^3)	0.7	0.1	0.2	0.5	**1.2**
Utility Investment (Millions, 2014$)	$2.2	$0.5	$0.4	$0.5	**$3.5**
Customer Investment (Millions, 2014$)	$0.2	$0.1	$0.1	$0.2	**$0.6**
Total DSM Investment (Millions, 2014$)	$2.3	$0.6	$0.5	$0.7	**$4.1**

Estimated Average Annual Bill Reduction per Customer (Electric): $8,840

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $10,779

**Includes estimates for 2013/14*

New Buildings Program

The New Buildings Program is an 8-year program that began in 2010. Its primary objective is to transform the commercial new construction industry in preparation for pending building codes which will require significant improvements in overall building energy efficiency. The program offers technical assistance and financial incentives for customers designing and constructing new, energy efficient commercial buildings.

The provincial government has adopted the National Energy Code of Canada for Buildings (NECB) 2011 into the Manitoba building code. Coming into force December 1, 2014, this adoption will have a significant impact on the energy efficiency of new commercial buildings and will affect many disciplines in Manitoba's construction industry, including the code enforcement authorities.

Two incentive options are currently offered to all customers: The Prescriptive Path, which specifies minimum design criteria for common building types or the Custom Design Path, which offers building designers flexibility to create energy efficient buildings. Power Smart buildings are designed to use at least 33% less energy than similar buildings designed to meet the Model National Energy Code of Canada for Buildings 1997 (MNECB 97). Custom Design Path participants are eligible for an energy modeling incentive and are also given the option to enroll in the Proven Performance Path which provides further incentives for energy efficiency beyond the program's minimums. The target market is all new commercial buildings constructed in Manitoba and represents approximately 200 new commercial building projects in the province each year. In order to move the market toward the energy efficiency requirements proposed under the upcoming building code, the industry faces fundamental changes to the current methods of designing, constructing, and commissioning commercial buildings. A lack of qualified, local firms offering integrated design, energy modeling, and building commissioning; industry perceptions of higher initial capital costs associated with designing and constructing energy efficient buildings; and a lack of customer and industry knowledge about lifecycle costing creates barriers to constructing energy efficient buildings. To help overcome these barriers, Manitoba Hydro has worked closely with the Province's Green Building Coordination Team to develop the Green Building Policy for Government of Manitoba Funded Projects. This policy ensures the Province's investments in new construction will help transform the local market by leading by example, and will help build industry capacity within Manitoba. Program efforts are focused on larger and more complex projects in order to showcase the benefits of energy efficient buildings to a broader audience on a larger scale. Providing financial incentives along with industry training and support aids in addressing these barriers.

To date, there have been 33 buildings constructed that meet the Power Smart requirement of at least 33% more energy efficient than the MNECB 97. In addition to these completed projects, another 51 projects are currently registered to participate. The program is forecast to achieve a market penetration rate of 25% of annual buildings constructed being energy efficient in 2016/17.

	2009/10 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Buildings (annual)	33	30	40	50	**153**
Capacity Savings (MW)	1.4	4.6	10.8	18.6	**20.0**
Energy Savings (GW.h)	7.7	10.5	24.4	41.9	**49.6**
Natural Gas Savings (million m^3)	2.8	0.3	0.7	1.2	**4.0**
Utility Investment (Millions, 2014$)	$3.8	$3.1	$3.9	$4.5	**$15.3**
Customer Investment (Millions, 2014$)	$3.1	$6.7	$8.9	$11.2	**$29.9**
Total DSM Investment (Millions, 2014$)	$6.9	$9.8	$12.8	$15.7	**$45.2**

Estimated Average Annual Bill Reduction per Customer (Electric): $18,921

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $2,311

**Includes estimates for 2013/14*

Commercial Refrigeration Program

The Commercial Refrigeration Program was launched in 2006 to encourage commercial customers to reduce energy consumption by providing over 15 different product incentives for energy efficient upgrades to refrigeration display cases, walk-in boxes, mechanical rooms, and lighting. Savings are achieved by providing customers with information about best practices and maintenance, promoting energy efficient refrigeration technologies, and optimizing the operation of new and existing refrigeration equipment.

The target market is commercial customers with foodservice refrigeration equipment, primarily grocery, retail, and convenience stores. Many of the qualifying energy efficient refrigeration systems have higher incremental costs, and equipment upgrade decisions are sometimes based on aesthetics over energy efficiency. Offering financial incentives to lower incremental costs and promoting the energy and associated bill savings along with non-energy benefits of efficient refrigeration systems, such as increased comfort in refrigeration aisles for both customers and employees, reduced product spoilage, and extended equipment life for refrigeration motors and compressors, is effectively addressing these barriers.

The program forecasts strong participation going forward as a result of the high volume of activity stemming from a new entrant to the Manitoba market, Orange Energizing Solutions, a company that focuses on direct customer sales and installation of eligible refrigeration measures that require little or no investment from the customer. In addition, the program plans to implement an enhanced rural strategy that will offer increased incentives in areas of the province that are difficult to reach and underserviced by the commercial refrigeration service industry.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Locations (annual)	1,046	367	208	60	**1,681**
Capacity Savings (MW)	4.8	1.3	2.0	2.4	**7.2**
Energy Savings (GW.h)	32.6	11.7	17.9	21.3	**53.9**
Utility Investment (Millions, 2014$)	$3.0	$1.7	$1.5	$0.3	**$6.6**
Customer Investment (Millions, 2014$)	$3.6	$0.1	$0.1	$0.1	**$3.9**
Total DSM Investment (Millions, 2014$)	$6.6	$1.8	$1.6	$0.5	**$10.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $1,673					

**Includes estimates for 2013/14*

Commercial Kitchen Appliance Program

The Commercial Kitchen Appliance Program was launched in 2008 to encourage customers to choose ENERGY STAR steam cookers (gas and electric) and ENERGY STAR deep fat fryers (gas only) when replacing commercial appliances.

The target market for steam cookers and deep fat fryers consists of restaurants and foodservice establishments with either gas or electric commercial kitchen appliances. ENERGY STAR qualified appliances have a higher initial cost to purchase, and many customers are not aware that using ENERGY STAR appliances can decrease operating and maintenance costs and improve food quality. Providing financial incentives and promoting the various energy and non-energy benefits of ENERGY STAR kitchen appliances is effectively addressing these market barriers.

The program also plans to reintroduce the direct-install of pre-rinse spray valves - a previously discontinued Power Smart technology that was part of a successful program model that ran from 2006 through 2010. Since the original program's conclusion, the technology has evolved to a more efficient spray valve, thereby creating an opportunity to convert the Manitoba market, including previous participants, to the latest level of efficiency. Spray valves have a very similar target market as steam cookers and deep fat fryers, making it an obvious addition to the Commercial Kitchen Appliance Program.

	2008/09 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Appliances (annual)	107	630	834	1,187	**2,758**
Capacity Savings (MW)	0.2	0.7	1.7	3.1	**3.3**
Energy Savings (GW.h)	0.9	0.7	1.5	2.7	**3.5**
Natural Gas Savings (million m^3)	0.1	0.2	0.5	1.0	**1.1**
Utility Investment (Millions, 2014$)	$0.5	$0.2	$0.2	$0.2	**$1.1**
Customer Investment (Millions, 2014$)	$0.2	$0.0	$0.1	$0.1	**$0.3**
Total DSM Investment (Millions, 2014$)	$0.6	$0.2	$0.3	$0.3	**$1.4**

Estimated Average Annual Bill Reduction per Customer (Electric): $452

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $137

**Includes estimates for 2013/14*

Network Energy Management Program

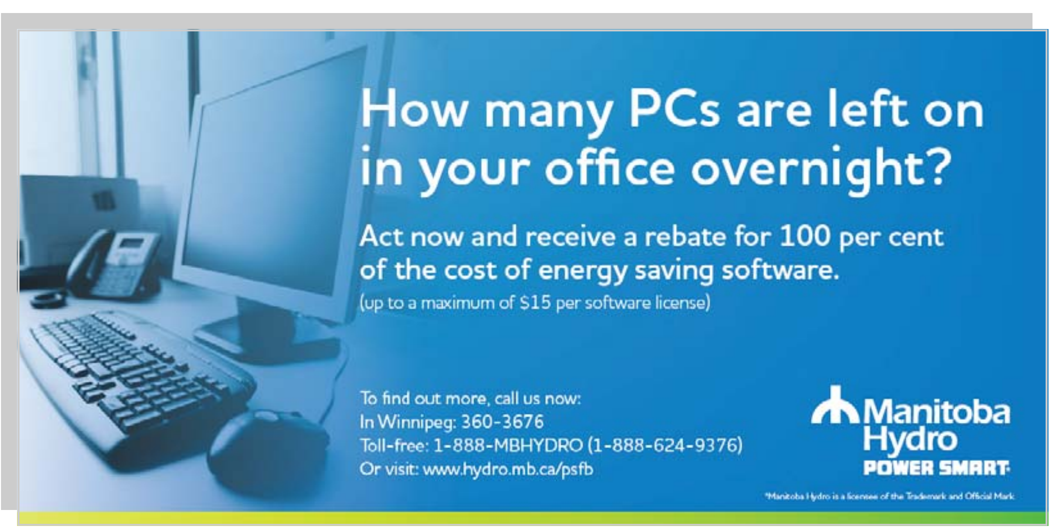
The Network Energy Management Program was launched in 2009 to encourage customers to install program-approved software that conserves energy by sending personal computers (PCs) into a mode that consumes less energy when they are not in use. The program is aimed at commercial organizations that manage a network of PCs.

The target market is comprised of approximately 2 500 physical locations in the school/college and office sectors, representing approximately 300 000 PCs. To streamline penetration into educational institutions, the program is seeking to create a strategic partnership with Manitoba Education Research and Learning Information Networks (MERLIN), the organization that brokers educational institutions with Information Technology (IT) products and services. Approximately 70 000 workstations are supported through this existing procurement system which, if successful, would yield significant energy savings for the program.

Installation, configuration, and testing of this new software on existing networks can require a significant time investment. Although management may realize operational cost savings, IT staff are often cautious when implementing software that they perceive may in any way restrict their ability to access individual PCs remotely to perform maintenance and system upgrades. The program provides financial incentives and promotes the product benefits through direct marketing to both management and IT staff in order to address these barriers to adoption.

	2009/10 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Licenses (annual)	4,631	3,343	5,562	7,784	**21,320**
Capacity Savings (MW)	0.1	0.2	0.5	1.0	**1.0**
Energy Savings (GW.h)	0.8	0.5	1.4	2.5	**3.3**
Utility Investment (Millions, 2014$)	$0.3	$0.1	$0.1	$0.1	**$0.6**
Customer Investment (Millions, 2014$)	$0.0	$0.1	$0.1	$0.1	**$0.2**
Total DSM Investment (Millions, 2014$)	$0.2	$0.1	$0.2	$0.3	**$0.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $4,929					

**Includes estimates for 2013/14*



Internal Retrofit Program

The Internal Retrofit Program (IRP) was launched in 1993 with the goal of retrofitting all Manitoba Hydro buildings to Power Smart levels during planned renovations and initiating energy efficiency improvements to corporate facilities when cost-effective to do so. The program assists with funding associated with the implementation of energy efficient measures including lighting, building envelope, HVAC, water, and custom measures. The program also ensures that newly constructed Manitoba Hydro facilities meet the requirements outlined in the Manitoba Green Building Policy. The program's target market is all existing Manitoba Hydro buildings that do not meet Power Smart levels, including generating stations, commercial buildings, and corporate housing. There are approximately 1000 Manitoba Hydro buildings province-wide and the program aims to have 100% of these facilities satisfy Power Smart requirements. To date, the Internal Retrofit Program has achieved energy savings of over 41 GW.h. The program end date is planned for the end of the 2017/18 fiscal year.

	1992/93 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	1,316	49	68	56	**1,489**
Capacity Savings (MW)	10.5	0.2	0.4	0.5	**11.0**
Energy Savings (GW.h)	41.9	1.3	2.4	3.3	**45.3**
Natural Gas Savings (million m^3)	0.0	0.0	0.0	0.0	**0.0**
Utility Investment (Millions, 2014$)	$13.0	$0.9	$0.9	$0.8	**$15.5**

**Includes estimates for 2013/14*

Power Smart Shops Program

The Power Smart Shops Program is designed to promote energy efficiency to small commercial customers including restaurants, food retail, non-food retail/services, and small offices. The program enlists a contractor to help customers save energy through the free installation of low cost energy efficient faucet aerators and low flow pre-rinse spray valves, as well as a free lighting assessment and written report that identifies opportunities to save energy by retrofitting inefficient lighting. Aggressive lighting incentives are available for retrofitting T8 fluorescent lamps to energy efficient T8 lamps, retrofitting T12 fluorescent lighting to T8's, replacing incandescent bulbs with LED screw-in bulbs, and retrofitting incandescent exit signs with LED exit signs. These upgrades will be administered by one contractor and, with a free estimate and generous incentives on the entire project cost including labour and electrical permit, it makes upgrading easy and convenient for the customer.

This particular market segment is a proven late adopter of energy efficient technologies due to a number of unique barriers that have not been specifically addressed by existing Power Smart for Business programs. Limited resources, costs of upgrades, and lack of industry exposure are all barriers that the Power Smart Shops program aims to help overcome by designating a single external contractor to carry out all aspects of this program. The program will also provide customers with information on other energy saving technologies and low/no cost energy saving tips.

	2009/10 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Projects (annual)	708	0	108	367	**1,184**
Capacity Savings (MW)	0.2	0.0	0.1	0.2	**0.4**
Energy Savings (GW.h)	0.8	0.0	0.2	0.8	**1.6**
Natural Gas Savings (million m^3)	0.0	0.0	0.0	0.0	**0.0**
Utility Investment (Millions, 2014$)	$0.7	$0.0	$0.1	$0.2	**$1.1**
Customer Investment (Millions, 2014$)	$0.0	$0.0	$0.0	$0.1	**$0.1**
Total DSM Investment (Millions, 2014$)	$0.8	$0.0	$0.2	$0.3	**$1.2**

Estimated Average Annual Bill Reduction per Customer (Electric): $36

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $6

**Includes estimates for 2013/14*

Support Program

The following convenient financing program offered by Manitoba Hydro supports the incentive-based programs by allowing customers to finance initial project costs and pay these costs back on their monthly Manitoba Hydro bill.

Power Smart for Business PAYS Financing

Power Smart for Business PAYS (Pay As You Save) Financing was launched in September 2013. The program's objective is to assist commercial customers in reducing their energy and water consumption by offering extended financing terms for energy efficiency upgrades such as T8, T5, and LED lighting, high efficiency and electric furnaces, condensing and near-condensing boilers, insulation, geothermal, CO2 sensors, custom measures (commercial and industrial applications), and WaterSense® labeled toilets and urinals. This offering compliments and supports the various incentive-based programs by assisting customers in managing the installation cost of their upgrade.

To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing repayment, thereby resulting in an energy bill that is slightly less than the total bill prior to the retrofit. The target market for this program consists primarily of small business owners and tenants as well as government, school and municipal buildings. Financing will be available for extended terms with 20 to 25 year amortization periods dependent on the upgrade, with the interest rate being fixed for the first 5 years. These are projects that would not likely have occurred without the availability of this convenient and flexible financing offering.

	2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Loans (annual)	24	25	35	28	**112**
Capacity Savings (MW)	0.7	0.1	0.1	0.2	**0.9**
Energy Savings (GW.h)	2.5	0.3	0.5	0.8	**3.3**
Natural Gas Savings (million m^3)	0.0	0.0	0.1	0.1	**0.0**
Average Loan Amount: $13,104					

**Includes estimates for 2013/14*

Industrial

Manitoba Hydro offers incentive-based programs to address opportunities within the industrial market. These programs take a customer-focused approach to identify and address operating and production challenges in a manner that not only improves overall energy efficiency, but enhances productivity and competitiveness for Manitoba industry.

Manitoba's industrial market can be characterized as consisting of a large variety of industries with a broad size demographic of customers within each classification. While some sectors are responsible for higher percentages of consumption than others, no one industry sector is dominant within the province. In Manitoba, each sector is typically dominated by less than six customers, with the remaining customers being smaller with more specialized operations or substantively lower outputs. This diversity presents some unique challenges as opportunities to capture substantive savings are tied directly to specific industry business cycles within each industry sector that dictate major events such as equipment change-outs, plant overhauls, facility expansions, and new plant construction. These cycles are periodic and can stretch across decades.

Manitoba Hydro's industrial Power Smart programs must have broad appeal in order to be relevant and responsive to the needs of a diverse population of industrial customers.

Incentive Based Programs

Performance Optimization Program

The Performance Optimization Program was originally launched in June 1993 to promote energy efficiency through the optimization of electric motor-driven industrial systems such as air compressors, pumps, fans and blowers, optimization of industrial refrigeration, process heating, electro-chemical processes systems, and implementation of plant-wide energy management systems. The program is designed to provide industrial and large commercial customers with technical support and financial incentives to assist in the identification, investigation, and implementation of system efficiency improvements throughout a facility.

The target market consists of approximately 2 000 industrial customers, with the program being available to both existing facilities and new construction projects. Emphasis is placed on the 300 largest customers who represent about 1/3 of the energy consumed in Manitoba. The average duration of a project from identification of the opportunity to implementation ranges from 6 months to 2 years, averaging approximately 18 months.

The actual number of project applications facilitated in any fiscal year and the savings achieved per project can vary dramatically based on project size, equipment age, and remaining life of the individual systems being optimized. However, savings levels are relatively consistent, thereby reflecting the capability within Manitoba Hydro's programs to adapt to available opportunities. Targeted companies may have multiple eligible energy conservation projects that are captured in a short period of time, resulting in intense periods of activity in a company or industry sector followed by a lull in activity thereafter as investment is recouped and productivity gains are utilized.

	1993/94 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Capacity Savings (MW)	99.9	2.7	5.8	9.4	**109.3**
Energy Savings (GW.h)	517.2	17.1	37.1	60.0	**577.2**
Utility Investment (Millions, 2014$)	$35.5	$5.9	$6.9	$7.9	**$56.2**
Customer Investment (Millions, 2014$)	$88.1	$0.7	$0.8	$0.9	**$90.5**
Total DSM Investment (Millions, 2014$)	$123.6	$6.6	$7.7	$8.9	**$146.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $7,895					

**Includes estimates for 2013/14*

Natural Gas Optimization Program

The Natural Gas Optimization Program (NGOP) is a 12-year program that was launched in September 2006. Its primary objective is to support the systematic improvement of natural gas equipment and processes for industrial and large institutional customers. The program supports customers by offering financial incentives for steam trap audits, feasibility studies, and energy efficient project implementation. The program was principally developed to promote custom applications within large industrial, institutional, and commercial facilities comprised of roughly 1 400 customers in Manitoba. Since the launch of the program, it has become apparent that the small-to-medium industrial customers are also interested in pursuing energy efficiency with support from Manitoba Hydro. The scope of the NGOP has since been expanded to allow the program to respond to all industrial customer inquiries, regardless of the size of the facility or volume of natural gas consumed.

Like the Performance Optimization Program, the NGOP is a custom program that supports a variety of technologies across a wide variety of applications including boiler conversions, process water and air heat recovery, process equipment and pipe insulation, boiler economizers, and other available technologies. The program is designed to address key market barriers related to project costs, available benefits, cost/benefit ratios, and desired return on investment. Current low natural gas commodity prices are challenging Manitoba Hydro customers' desired rates of return on investment in conservation initiatives.

	2006/07 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Natural Gas Savings (million m^3)	14.0	1.2	2.4	3.6	**17.6**
Utility Investment (Millions, 2014$)	$4.5	$0.6	$0.6	$0.6	**$6.2**
Customer Investment (Millions, 2014$)	$24.6	$2.0	$2.0	$2.0	**$30.7**
Total DSM Investment (Millions, 2014$)	$29.0	$2.6	$2.6	$2.6	**$36.9**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $22,247					

**Includes estimates for 2013/14*

Bioenergy Optimization Program

The Bioenergy Optimization Program was launched in 2008 to encourage customers to install, operate, and maintain customer-sited load displacement generation systems that employ combined heat and power (CHP) and renewable fuels, specifically biomass. The target market consists of customers that have readily available, low-cost sources of biomass, a continual need for heat and power, and the capability to operate and maintain biomass-to-energy conversion systems. A lack of proven demonstration projects of biomass-to-energy is a key barrier for many customers, considering the high initial costs for many of these systems. To increase awareness and knowledge of bioenergy opportunities, Manitoba Hydro has undertaken five demonstration projects over the past 3 years. Increased awareness combined with incentives are expected to increase customer interest and acceptance of bioenergy systems. Manitoba Hydro's program further supports customers in developing a thorough understanding of the costs and benefits of bioenergy systems, assisting with the development of strong business cases for future installations.

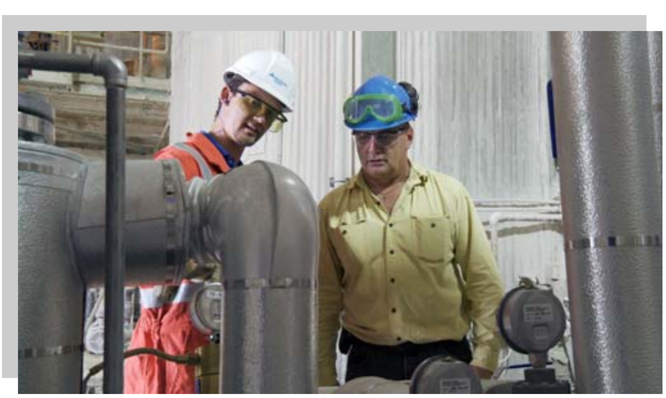
Major customer sectors targeted include industrial, Hutterite colonies, and livestock production. The size of these systems is anticipated to be smaller during the earlier stages of the program, primarily due to the high cost of the systems. Installations are anticipated to grow in size as comfort with these technologies matures. While initial projections for customer participation are relatively modest, opportunities for larger savings exist in larger industrial facilities with substantial waste streams and considerable need for combined heat and power systems to support their operations. Government policy on renewable energy is anticipated to be a factor in the future uptake of load displacement generation systems in Manitoba.

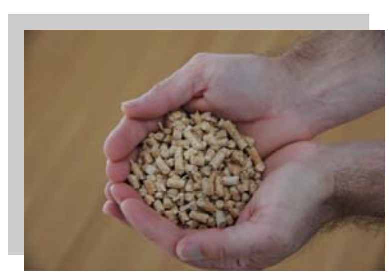
	2008/09 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
Capacity Savings (MW)	58.3	1.6	3.4	4.7	**63.0**
Energy Savings (GW.h)	209.2	14.3	29.5	41.1	**250.3**
Natural Gas Savings (million m^3)	0.0	0.0	0.7	0.9	**0.9**
Utility Investment (Millions, 2014$)	$11.2	$2.1	$2.7	$1.8	**$17.8**
Customer Investment (Millions, 2014$)	$27.1	$2.4	$3.5	$2.4	**$35.3**
Total DSM Investment (Millions, 2014$)	$38.3	$4.4	$6.2	$4.2	**$53.1**

Estimated Average Annual Bill Reduction per Customer (Electric): $81,687

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $26,946

**Includes estimates for 2013/14*





Customer-Sited Load Displacement

The Customer-Sited Load Displacement Program encourages customers to install, operate, and maintain customer-sited load displacement generation systems that employ combined heat and power (CHP) and rely on the use of waste streams and by-products, locally available, low cost sources of biomass fuel, and other renewable energy sources. The target market consists of several large-sized customers or customer sectors that are striving to optimize their operations and improve environmental performance.

Waste streams and by-products from manufacturing operations typically present a cost of disposal and an environmental liability to the manufacturer. Being able to convert waste streams and by-products into useful energy for the manufacturing operation is potentially a more sustainable practice and a means to reduce energy and disposal costs. Similarly, locally available low cost sources of biomass such as waste wood and crop residues can be harnessed as a sustainable and economic fuel source for on-site heat and power generation applications. Other emerging energy sources such as wind and solar may have potential in certain instances to offset purchased energy. Manitoba Hydro's new Customer-Sited Load Displacement Program offers technical and financial support to understand the feasibility to use these types of fuel sources, to implement the equipment and systems for load displacement generation, and to ensure ongoing, reliable operation of the energy production equipment.

Major customer sectors targeted by the program include forestry, chemicals, metals, oil and gas, and wastewater treatment. The size of these systems is anticipated to range from 1 MW to 15 MW of electrical load displacement via on-site generation. Installations are anticipated to cost between $3,500 to $5,000 per kW electric installed. Customer costs will be dependent upon existing infrastructure and operational capability. Government policy on renewable energy is anticipated to be a factor in future uptake of load displacement generation systems in Manitoba.

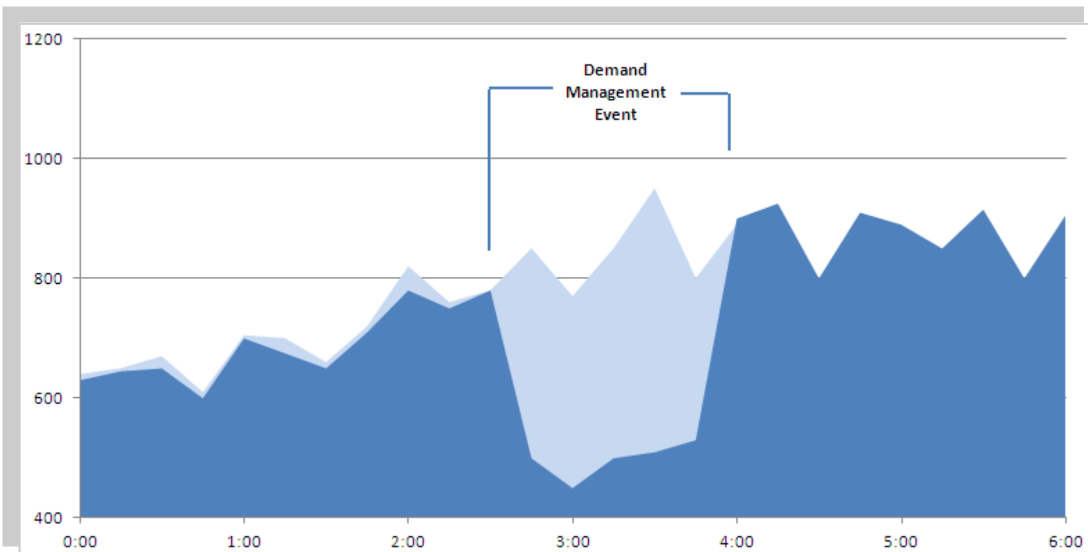
	2014/15	2015/16	2016/17	Total to 2016/17
No. of Customers (annual)	11	14	7	**32**
Capacity Savings (MW)	24.1	37.6	56.0	**56.0**
Energy Savings (GW.h)	137.5	191.0	335.6	**335.6**
Utility Investment (Millions, 2014$)	$1.6	$5.2	$21.4	**$28.1**
Customer Investment (Millions, 2014$)	$7.8	$17.5	$44.9	**$70.1**
Total DSM Investment (Millions, 2014$)	$9.4	$22.7	$66.3	**$98.3**
Estimated Average Annual Bill Reduction per Customer (Electric): Variable depending on project size				

Curtailable Rate Program

Under the Curtailable Rate Program, qualifying customers receive a monthly credit on load (kW) that can be curtailed on notice from Manitoba Hydro. To be eligible, customers' load/processes must be configured to allow them to meet the requested curtailment within the notification period as outlined under their chosen contract option.

	1990/00 to 2013/14*	2014/15	2015/16	2016/17	Total to 2016/17
No. of Customers (annual)	49	3	3	3	**58**
Capacity Savings (MW)	160.4	160.9	160.9	160.9	**160.9**
Utility Investment (Millions, 2014$)	$94.0	$6.0	$6.0	$6.0	**$111.9**

**Includes estimates for 2013/14*



Manitoba Hydro
POWER SMART



Power Smart Plan

2015/16

Manitoba Hydro's energy efficiency initiatives for 2015/16.

March 2015

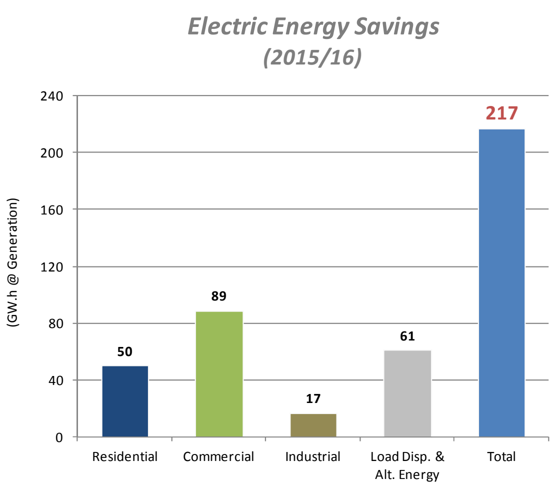
HIGHLIGHTS

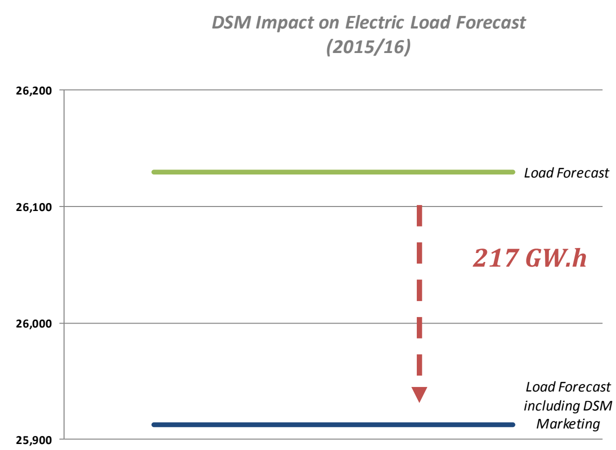
This report outlines Manitoba Hydro's Demand Side Management plan for the 2015/16 fiscal year. The plan outlines activity related to incentive based programs and excludes any activity associated with codes and standards. Manitoba Hydro has a strong commitment to DSM with a focus on pursuing all cost effective energy efficiency opportunities and continually monitoring the market for emerging trends and additional opportunities. To ensure all economic opportunities are being pursued, Manitoba Hydro updates its DSM plan every year.

Electric Energy Savings

In 2015/16, Manitoba Hydro plans to capture electricity savings of 204 MW and 217 GW.h. Along with constructing new renewable hydro generation, Demand Side Management is a key component of Manitoba Hydro's strategy for meeting the province's future energy needs. This level of energy savings represents 0.8% of the estimated load forecast in 2015/16 and 55% of expected annual load growth (20 year average). In 2015/16, Manitoba Hydro plans to capture electricity energy savings of 14 MW and 50 GW.h in the residential sector, 21 MW and 89 GW.h in the commercial sector, 160 MW and 17 GW.h in the industrial sector and 9 MW and 61 GW.h in the load displacement and alternative energy sector.

The planned electric energy savings in this plan are approximately 100 GW.h lower than previously forecast in the 2014-2017 Power Smart Plan, however the lower target is primarily due to a delay in energy savings associated with the Load Displacement program.

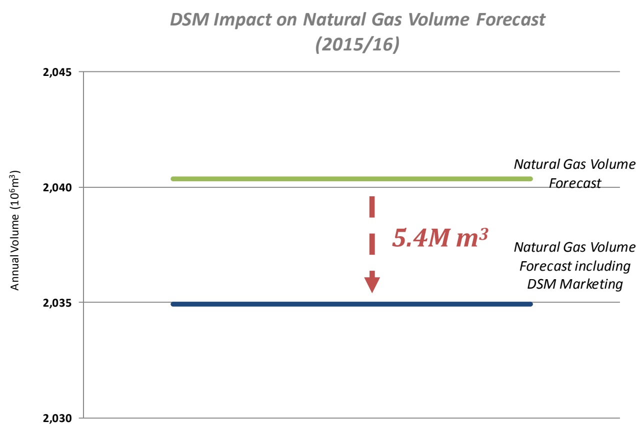


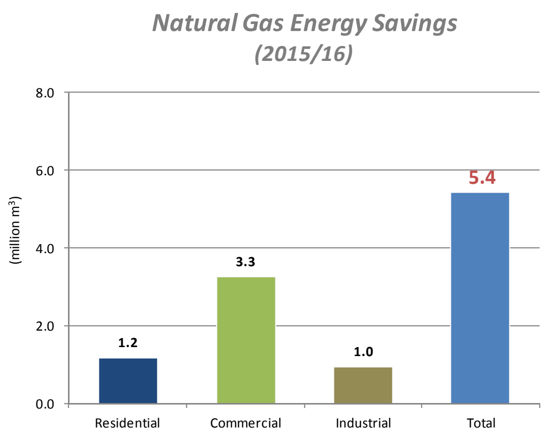


Natural Gas Savings

In 2015/16, the plan sets out to capture natural gas savings of 5.4 million cubic metres. This level of energy savings represents 0.3% of the estimated volume forecast in 2015/16, further reducing natural gas consumption in Manitoba. In 2015/16, Manitoba Hydro plans to capture natural gas savings of 1.2 million cubic metres in the residential sector, 3.3 million cubic metres in the commercial sector, and 1.0 million cubic metres in the industrial sector.

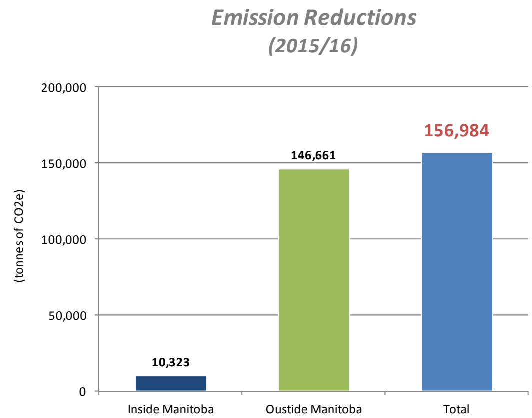
The natural gas savings expected to be achieved through this plan are 2.2 million cubic metres lower than previously forecast in the 2014-2017 Power Smart Plan due to interactive effects associated with achieving higher electricity savings and due to lower than forecast natural gas savings expected to be achieved through the Bioenergy Optimization program. In the latter case, initiatives previously expected in the hog industry will likely not transpire due to economics.





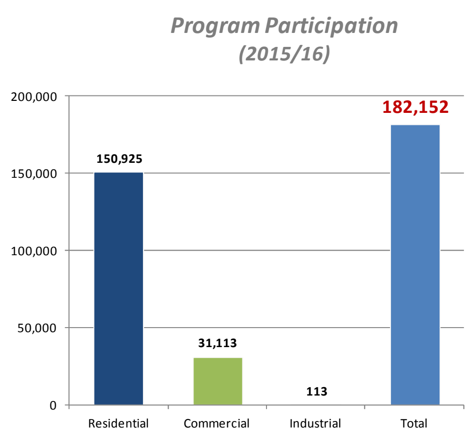
Greenhouse Gas Emission Reductions

Greenhouse gas emission reductions which will result from Manitoba Hydro's Demand Side Management investments are approximately 157,000 tonnes in 2015/16. This is equivalent to taking over 31,000 cars off the road for one year.



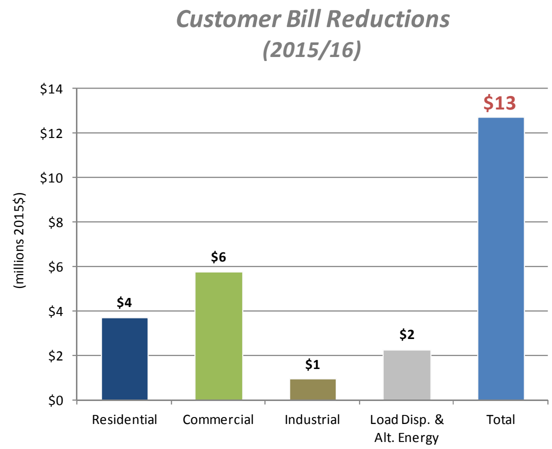
Customer Participation

In 2015/16, it is forecasted that over 182,000 customers will participate in Manitoba Hydro's Demand Side Management incentive based and support programs. In 2015/16, it is forecasted that approximately 151,000 residential customers, 31,000 commercial customers, and 100 industrial customers will participate in Manitoba Hydro's Demand Side Management incentive based and support programs.



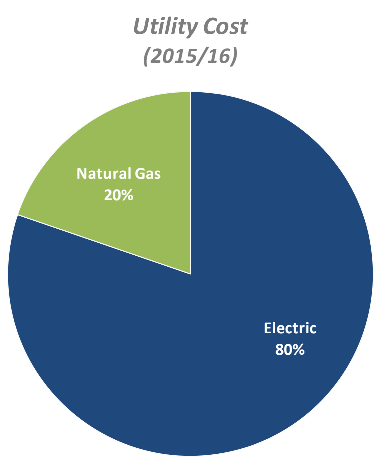
Customer Bill Savings

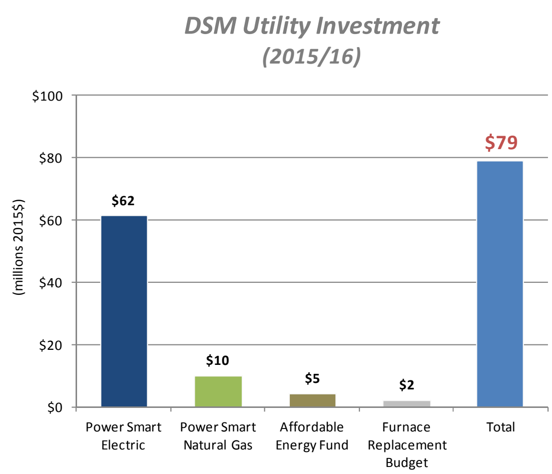
In 2015/16, customers who participate in Manitoba Hydro's Power Smart Programs will enjoy a forecast reduction of $13 million on their energy bills; $4 million for residential customers, $6 million for commercial customers, $1 million for industrial customers, and $2 million for load displacement and alternative energy customers.



Power Smart Investment

Over the next year, Manitoba Hydro plans to invest $79 million in Power Smart initiatives with $62 million of the costs funded through Manitoba Hydro's Power Smart electricity budget, $10 million funded through Manitoba Hydro's Power Smart natural gas budget, $5 million funded through the Affordable Energy Fund and $2 million funded through the Lower Income Natural Gas Furnace Replacement budget.





Manitoba Hydro Taking it to the Streets with the Neighbourhood Power Smart Project

Manitoba Hydro continues this aggressive marketing approach by partnering with neighbourhood groups to increase participation in this hard to reach market. Building on the success of the Neighbourhood Power Smart Project in William Whyte and Brandon. which saw over 140 homes participate in 2014/15, Manitoba Hydro is committed to making neighbouhoods Power Smart and will further increase participation by 100 homes in 2015/16. Working with North End Community Renewal Corporation and Brandon Neighbourhood Renewal Corporation, lower income customers can benefit from energy efficient upgrades with the assistance of a Community Coordinator and Social Enterprise Contractors completing the retrofits. This community-led initiative helps to reduce barriers to participation with a door-to-door approach and provides employment opportunities to members of the community.

First Nations Partnership Builds Strong Relationships with Free Home Upgrades and Employment for Community Members

Manitoba Hydro continues to have great success in delivering the First Nations Power Smart Program by working directly with First Nation Bands while building strong relationships. Manitoba Hydro is committed to increasing the energy efficiency in First Nation Communities as evidenced by its aggressive approach with a dedicated First Nations Energy Advisor. The program provides free insulation upgrades for qualifying homes which improves the energy efficiency and comfort of their homes, reduces energy bills, and provides employment for members in the community to complete the installation. Over 1,400 homes have had insulation upgrades through the Program. In the fall of 2014, the First Nations Power Smart Program launched another energy efficiency initiative, Direct Install. This initiative will provide customers access to free items such as LED light bulbs, showerheads, faucet aerators, pipe wrap, window kits, and draft stoppers to help reduce the cost of their energy bills. Funding is provided to employ local members of the community to complete the installation. The First Nations Power Smart Program plans to complete 1,000 installs annually until all homes in First Nation Communities receive the upgrades. Manitoba Hydro can also work directly with First Nation Communities to develop an Energy Plan best suited for their specific needs.

Unique Manitoba Hydro Partnership with Drain Water Heat Recovery Systems Provides Training and Reduces Tenant Bills

The Affordable Energy Program once again successfully partnered with Manitoba Housing and Building Urban Industries for Local Development (BUILD), to complete a Drain Water Heat Recovery Pilot program in 50 Manitoba Housing units. This unique partnership enables on the job apprenticeship for BUILD trainees and provides lower income tenants with an opportunity to reduce their energy bills. It is estimated an additional 1,500 Drain Water Heat Recovery Systems will be installed in Manitoba Housing units.

Recognizing the financial burden of lower income customers, Manitoba Hydro continually explores additional energy savings measures to further reduce utility bills. As a result, the Drain Water Heat Recovery System will also be offered for free to all qualifying Affordable Energy Program customers – including First Nations, Not for Profit Social Housing and Private Homes for both owners and tenants in spring 2015.

Manitoba Hydro Explores Heat Pump Feasibility in Manitoba's Cold Climate

Manitoba Hydro is investigating the potential market for both heat pump water heaters and cold climate air source heat pumps in the Province as alternative heating sources.

Many homeowners are converting their existing standard efficiency gas water heaters to electric water heaters to eliminate venting concerns and reduce installation costs. New homes with high efficiency natural gas heating systems are almost exclusively installing electric water heaters because of their lower installation cost as compared to the alternative of side vent gas water heaters. Heat pump water heaters, which pulls heat from the surrounding air and dumps it - at a higher temperature - into a tank to heat water, may be an energy efficient alternative.

A proposal for a contribution agreement with Natural Resources Canada to assist in funding four homes for monitoring is in the final stages. If approved, monitoring equipment will be installed in the fall of 2015.

Similar to geothermal heat pumps, which uses the earth as its primary heating source, air source heat pumps (ASHP) use the outdoor air to heat and cool the home. Conventionally, ASHP were used in milder climates where outdoor temperatures remain above 0°C because as the outdoor air temperature drops below this mark, the output and efficiency of these units drops exponentially. Cold climate ASHP were later designed to operate under -23°C, however, little to no field testing has been published regarding their actual operating efficiency compared to test data.

Manitoba Hydro will be monitoring two ducted cold climate heat pump systems with inverter driven compressors during 2015. Field monitoring for one full year of operation will assist in providing base line performance for these technologies and will help determine the feasibility of offering a related Power Smart program.

Community Program Promotes Job Growth Through Energy Efficiency

The Community Geothermal program, in partnership with the social enterprise group Aki Energy assists First Nation communities with the installation of geothermal heat pump systems to reduce their overall home energy costs. The Program also trains band members on the installation of the heat pump systems, encouraging local job growth within the community. This program is the first of its kind in Canada and it strives to help make Manitoba's First Nations the most energy efficient in the country.

The Program built on the success of the pilot and added two more First Nations for the 2014 installation season, for a total of four First Nations participating. To date, 45 community members have been trained and nine of those went on to receive full International Ground Source Heat Pump (IGSHPA) certification.

In 2014, 37 new homes were built in the participating communities where geothermal heat pump systems were installed as their primary heating system over a conventional electric system. A commitment was made by all participating First Nations that all future new construction housing will have a geothermal heat pump system installed.

For the upcoming 2015 installation year, First Nation participants met with Manitoba Hydro and established that, at minimum, 135 systems will be installed in each community. As well, the participating First Nations and Manitoba Hydro will review their commercial buildings to assess the potential savings with respect to retrofitting to energy efficient technologies.

Solar Hot Water Tanks Heat Up First Nations

Building upon the Community Geothermal program, a solar hot water tank pilot was established in Peguis First Nation to monitor the systems for future program potential. The Solar Hot Water Tank program promotes the installaton of solar hot water tank systems over the conventional electric tank systems. These systems use heat from sunlight to pre-heat water that enters the water tank. The water heater will require less energy to reach the desired temperature for all the household hot water needs. These systems work best for residences with five of more occupants, making First Nation communities the ideal candidate for these systems. Two community members were trained on the installation of the system by the system distributor with a plan to install all twenty units by the end of March 2015. Manitoba Hydro will be monitoring four of the systems throughout the 2015 year and will be assessing the data for potential savings with the potential to expand the Community Program to offer a solar hot water tank initiative to all First Nations.

Power Smart and Local Home Builders Spur Innovative Building Practices in Manitoba

In 2014, Manitoba Hydro sponsored Natural Resources Canada's Local Energy Efficiency Partnerships (LEEP) initiative. Through LEEP, a group of regional builders worked together to brainstorm and assess a broad range of energy efficient technologies. Builders then shortlisted the most promising options, attending manufacturer presentations and employing the selected technologies in field trials. LEEP allows builders to reduce their time and risk in finding and trying innovations in order to build higher performance homes better, faster and more affordably.

LEEP builders, their staff, and sub-trades participated enthusiastically throughout the busy spring 2014 construction ramp-up. All builders have confirmed they will be deploying and showcasing LEEP-selected energy efficient technologies for the field trial phase of the initiative at the 2015 Fall Parade of Homes.

With approximately 3700 new homes built in Manitoba every year, innovation in new construction is essential to continually reduce the energy consumed by residential buildings. Pursuing new technologies through Power Smart efforts in tandem with advances in building code will ensure that energy efficiency remains a key consideration in home design.

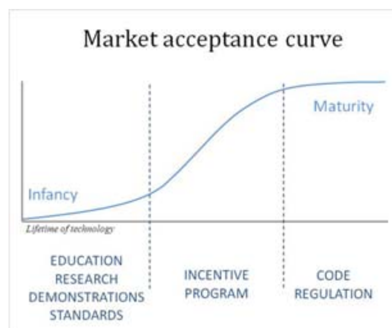
DSM STRATEGY

Manitoba Hydro's DSM strategy is to aggressively pursue all cost-effective energy efficiency opportunities and continually monitor the market to identify emerging trends and opportunities that may become viable and cost-effective DSM initiatives within the planning horizon.

Manitoba Hydro's DSM initiative, marketed under the Power Smart brand, is designed to encourage the efficient use of energy in residential, commercial, and industrial customer sectors. Manitoba Hydro's overall DSM strategy involves taking a broad approach to capturing energy efficiency opportunities: education to build awareness and understanding, creating foundations through the support of standards, motivating customers with the aid of financial tools, and entrenching energy savings through the support of federal and provincial codes and regulations.

In assessing options for pursing a DSM opportunity, Manitoba Hydro uses a number of metrics as guidelines to assess energy efficient opportunities. These metrics assist in determining whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options, and the relative investment sharing between ratepayers and participating customers. These metrics include the Total Resource Cost, Societal Cost, Rate Impact Measure, Levelized Utility Cost, and Customer Simple Payback. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

As outlined in the following graph, Manitoba Hydro takes a three stage approach to achieving market transformation. In the infancy stage of emerging opportunities, Manitoba Hydro supports these technologies by building customer awareness, demonstrations, and/or through investments in research and development. As market acceptance increases and the opportunity becomes cost-effective, financial incentives and/or other market intervention strategies are pursued to encourage customers to install the technology. As the product matures and market adoption grows, incentive-based programming generally becomes uneconomic. During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. This latter strategy also ensures permanent market transformation for the specific energy efficiency opportunity.



An Example: Changing Furnace Efficiencies in Manitoba

In 2001, only 30% of all natural gas furnaces being installed in Manitoba were high-efficient models and customer awareness of higher efficiency options was low. In response to this market situation, Manitoba Hydro launched the Power Smart Residential Loan and supporting Home Comfort and Energy Savings campaign to educate and promote the installation of high efficient natural gas furnaces. This approach laid the foundation for customers to consider the energy efficient alternative, and provided a tool for contractors to promote this technology. In 2005, to further increase market acceptance, a $245 incentive was introduced to encourage customers to choose high efficient natural gas furnaces over the less efficient alternative. By 2007, high efficiency furnaces had grown to represent 76% of all furnaces being replaced in Manitoba homes. In 2008, to accelerate the number of customers upgrading their furnaces, Manitoba Hydro increased their rebate to $500 for a limited time offering and aggressively promoted the financial and comfort benefits of upgrading a furnace. As market acceptance increased, Manitoba Hydro worked with the Province of Manitoba to develop the framework to regulate the minimum efficiency of all natural gas furnaces installed in Manitoba. On December 30, 2009, with market penetration of 86%, the Power Smart incentive ended and the Provincial regulation took effect requiring a minimum 92% AFUE for natural gas furnaces installed in Manitoba.

POWER SMART PLAN

The 2015/16 Power Smart Plan was developed through an intensive planning process and it offers programs and initiatives to pursue opportunities in all market sectors; residential, commercial, and industrial. These programs are designed based on in-depth knowledge of the technology and the market environment. An in-depth understanding is essential to ensure that the program design is adequately and effectively addressing the appropriate target market and contains the tools and strategies to address market barriers.

The following table outlines the forecasted achievements of 2015/16:

Programs	Participation Definition	2015/16 Participation	Capacity Savings (MW)	Energy Savings (GW.h)	Natural Gas Savings (million m^3)	Utility Investment (Millions, 2015$)
Service Extension Initiative for New Homes	No. of houses	0	0.0	0.0	0.0	$0.0
Home Insulation Program	No. of houses	2,286	2.2	4.3	0.7	$3.2
Water and Energy Saver Program	No. of houses	29,000	0.8	4.6	0.8	$2.1
Affordable Energy Program	No. of retrofits	2,725	2.6	6.2	1.4	$9.4
Refrigerator Retirement Program	No. of appliances	11,000	1.6	15.2	0.0	$2.3
Drain Water Heat Recovery Initiative	No. of houses	1,856	0.3	1.9	0.0	$0.6
Residential LED Lighting Program	No. of bulbs	392,724	4.0	12.7	0.0	$2.6
Community Geothermal Program	No. of systems	220	1.9	3.8	0.0	$1.5
Power Smart Residential Loan	No. of loans	5,700	0.3	0.5	0.3	$0.0
Power Smart PAYS Financing	No. of loans	336	0.1	0.3	0.0	$0.0
Residential Earth Power Loan	No. of loans	130	0.3	0.7	0.1	$0.0
Residential Programs			**14.1**	**50.1**	**3.2**	**$21.7**
Commercial Lighting Program	No. of projects	767	10.3	39.3	-	$8.9
LED Roadway Lighting Conversion Program	No. of conversions	27,863	1.6	10.8	-	$11.0
Commercial Building Envelope - Windows Program	No. of projects	225	1.0	2.1	0.3	$1.7
Commercial Building Envelope - Insulation Program	No. of projects	230	1.0	2.2	0.8	$2.1
Commercial Geothermal Program	No. of buildings	23	1.2	2.4	-	$0.5
Commercial HVAC Program - Boilers	No. of boilers	117	-	-	1.0	$1.1
Commercial HVAC Program - Chillers	No. of chillers	24	0.0	5.1	-	$0.5
Commercial HVAC Program - CO2 Sensors	No. of sensors	112	0.1	0.2	0.1	$0.2
Commercial HVAC Program - Water Heaters	No. of water heaters	25	-	-	0.0	$0.1
Commercial Custom Measures Program	No. of projects	9	0.1	0.6	0.1	$0.5
Commercial Building Optimization Program	No. of buildings	2	0.1	0.3	0.1	$0.4
New Buildings Program	No. of buildings	40	4.2	14.0	0.4	$3.8
Commercial Refrigeration Program	No. of locations	310	1.1	9.5	0.0	$0.8
Commercial Kitchen Appliance Program	No. of appliances	970	0.2	0.9	0.3	$0.3
Network Energy Management Program	No. of licenses	1,932	0.0	0.3	0.0	$0.1
Internal Retrofit Program	No. of projects	23	0.2	0.8	0.0	$0.7
Power Smart Shops	No. of projects	500	0.1	0.6	0.0	$0.3
Power Smart for Business PAYS Financing	No. of loans	33	0.0	0.0	0.0	$0.0
Commercial Programs			**21.2**	**89.1**	**3.2**	**$32.8**
Performance Optimization Program	No. of projects	96	2.1	17.0	-	$5.2
Natural Gas Optimization Program	No. of projects	12	-	-	1.0	$0.5
Indutrial Programs			**2.1**	**17.0**	**1.0**	**$5.7**
Energy Efficiency Subtotal			**37.4**	**156.2**	**7.3**	**$60.2**
Curtailable Rate Program	No. of customers	3	157.8	-	-	$6.0
Load Management			**157.8**	**-**	**0.0**	**$6.0**
Bioenergy Optimization Program	No. of projects	1	0.6	3.8	0.0	$0.8
Customer Sited Load Displacement	No. of customers	1	8.0	57.2	0.0	$5.5
Load Displacement & Alternative Energy			**8.6**	**61.0**	**0.0**	**$6.3**
Interactive Effects			-	-	-1.9	-
Program Support			-	-	-	$6.4
Power Smart Plan - 2015/16			**204**	**217**	**5.4**	**$79.0**

Residential

Manitoba Hydro offers a number of innovative programs, using a variety of market intervention tools including but not limited to, incentives, financing, education, energy assessments, to address opportunities in the residential market.

Service Extension Initiative for New Homes

Over the 2015/16 year, Manitoba Hydro will be exploring in detail the potential for an innovative and non-traditional approach to accelerate market transformation of cost-effective energy efficient technologies and building practices in the residential new construction market.

Manitoba Hydro recognizes that customers have many decisions to make when building a new home, and that a customer's focus may be on other more esthetic home upgrades such as flooring, cabinets, countertops, or other options, rather than energy efficiency or the type of heating systems of their new home. In many cases as part of their basic offerings, the homebuilder sets the building envelope design and mechanical systems to be incorporated. Through initiatives such as LEEP, Manitoba Hydro is working with industry to investigate the next opportunities for energy efficiency.

Building on this type of innovation and on the connections that Manitoba Hydro has with property developers and homebuilders as they request electric and natural gas service for their properties, Manitoba Hydro will be exploring in detail the opportunities to leverage service extension and allowance policies to encourage greater adoption of energy efficient opportunities

The initiative will focus on new residential single detached and multi-attached home construction in the province of Manitoba. Savings would not be expected to be realized in 2015-16 due to seasonal planning and building cycles in Manitoba.

Home Insulation Program

The Home Insulation Program was launched in May 2004 and is scheduled to run until March 31, 2027. In 2015/16, the program is expected to retrofit 886 electrically heated homes and 1,400 natural gas heated homes, achieving 4.3 GW.h and 2.2 MW of electric savings and 0.7 million cubic metres of natural gas savings. Combined with achievements to date, over 13,000 electrically heated homes and over 25,000 natural gas heated homes will be retrofitted, resulting in 65.4 GW.h and 32.6 MW of electric savings and 13.3 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 37% of targeted electric customers and 19% of targeted natural gas customers by the end of 2015/16.

The program is designed to encourage existing electric and natural gas heated homes to upgrade insulation levels and air sealing in their homes' attics, walls, and foundations. The overall target market for the program is approximately 35,000 electric and 129,000 natural gas homes. The program has been designed to address barriers to the adoption of energy efficient insulation including the lack of customer awareness regarding the financial and comfort benefits of increased insulation levels, the upfront capital cost of the upgrade, and the lack of priority when compared to more aesthetic and visible renovation projects. These market barriers are addressed through a comprehensive strategy that includes financial incentives to reduce the cost of the upgrade, informational materials in the form of advertising campaigns, and renovation "how to" booklets that provide technical guidance for upgrading insulation to Power Smart levels. Also, in 2014, Manitoba Hydro implemented a targeted outreach initiative in electric heated communities, offering in-home energy assessments to assist customers in identifying the highest potential energy efficiency upgrades. Power Smart on-bill financing programs are also promoted to provide additional encouragement for customers that are reluctant to consider allocating their renovation budget towards adding insulation to their home.

	2004/05 to 2014/15*	2015/16	Total to 2015/16
No. of Houses (annual)	36,531	2,286	**38,817**
Capacity Savings (MW)	30.5	2.2	**32.6**
Energy Savings (GW.h)	61.1	4.3	**65.4**
Natural Gas Savings (million m^3)	12.7	0.7	**13.3**
Utility Investment (Millions, 2015$)	$39.6	$3.2	**$42.8**
Customer Investment (Millions, 2015$)	$25.3	$1.5	**$26.8**
Total DSM Investment (Millions, 2015$)	$64.9	$4.7	**$69.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $330			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $146			

*Includes estimates for 2014/15

Affordable Energy Program

The Affordable Energy Program (AEP) was launched in December 2007 and is scheduled to run until 2028/29. In 2015/16, program participation is expected to be 2,725 customers, resulting in 6.2 GW.h and 2.6 MW of electric savings and 1.4 million cubic metres of gas savings. Combined with achievements to date, 13.341 customers will participate resulting in 23.6 GW.h and 10.6 MW of electric savings and 8.5 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 11% of targeted customers by the end of 2015/16.

The program is designed to assist lower income homeowners in implementing energy efficiency upgrades, such as improved insulation, high efficiency natural gas furnaces, various basic energy efficiency measures and drain water heat recovery systems. These upgrades can provide significant energy savings, decreasing the customer's monthly energy bills while increasing the comfort of their home. The criteria for determining program eligibility are the Low Income Cut-Off (LICO) thresholds set by Statistics Canada; customers' total household income must fall below 125% of the LICO thresholds for inclusion in the program. There are approximately 115,000 homes in Manitoba, excluding multi-unit residential buildings, that fall below the LICO 125% threshold; 105,000 customers own their home, while 10,000 customers rent. The primary targets within this market are homes with poor or fair insulation levels and standard efficient furnaces. They make up 22% (25,298) and 18% (20,525) of the market, respectively.

The program was designed recognizing the unique barriers lower income customers face in completing energy efficiency retrofits. Manitoba Hydro assists and encourages participation in this market by minimizing the financial burden with free insulation upgrades, a free drain water heat recovery system, a high efficiency natural gas furnace for $9.50/month for 5 years, and free basic energy efficiency measures (e.g. LEDs, showerheads, faucet aerators). The program expansion to include landlords has been successful in helping reach lower income Manitobans who rent in reducing their utility bills. The program is delivered through a number of approaches including direct participation with individual customers or through community groups (e.g. First Nations', Neighbourhood communities, social enterprises). Through these approaches, customers are made aware of the value of energy efficiency retrofits, along with the benefits of participating in the program. Customers are targeted through advertising and community-based campaigns, customized information sessions, and community networks. A community-led initiative, the Neighbourhood Approach, began in fall 2012 with the goal of completing energy efficiency upgrades on a block-by-block basis in lower income neighbourhoods. Under this approach, North End Community Renewal Corporation and Brandon Neighbourhood Renewal Corporation employ local residents and social enterprises, Building Urban Industries for Local Development (BUILD) and Brandon Energy Efficiency Program (BEEP), to bring energy efficiency upgrade opportunities direct to the customer's door.

To date, an estimated 10,616 energy efficiency retrofits have been completed. Of the total retrofits, 7,201 insulation projects have been completed and 3,810 furnaces have been replaced. The program is forecast to reach 68% (17,268) of the targeted homes with poor or fair insulation levels within the total LICO 125% market by 2026/2027. By 2022/23 the program is forecast to reach 56% (5,312) of standard furnaces within the total LICO 125% market with the other 44% (4,135) being replaced through attrition.

	2007/08 to 2014/15*	2015/16	Total to 2015/16
Total Participation (annual)	10,616	2,725	**13,341**
No. of Insulation Projects (annual)	7,201	1,315	**8,516**
No. of Furnaces Installed (annual)	3,810	686	**4,496**
No. of Boilers Installed (annual)	89	15	**104**
No. of Drain Water Heat Recovery Systems (annual)	50	950	**1,000**
Capacity Savings (MW)	8.0	2.6	**10.6**
Energy Savings (GW.h)	17.3	6.2	**23.6**
Natural Gas Savings (million m^3)	7.1	1.4	**8.5**
Utility Investment (Millions, 2015$)	$42.1	$9.4	**$51.5**
Customer Investment (Millions, 2015$)	$1.7	$3.4	**$5.1**
Total DSM Investment (Millions, 2015$)	$43.7	$12.9	**$56.6**
Estimated Average Annual Bill Reduction per Customer - Basic Measures (Electric): $86			
Estimated Average Annual Bill Reduction per Customer - Basic Measures (Natural Gas): $35			
Estimated Average Annual Bill Reduction per Customer (Electric) - Insulation: $598			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Insulation: $227			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Furnace: $241			
Estimated Average Annual Bill Reduction per Customer (Electric) - DWHR: $70			

*Includes estimates for 2014/15

Water and Energy Saver Program

The Power Smart Water and Energy Saver Program was launched in September 2010 and is scheduled to run until 2016/17. In 2015/16, program participation is expected to be 29,000, resulting in 4.6 GW.h and 0.8 MW of electric savings and 0.8 million cubic metres of gas savings. Combined with achievements to date, 169,247 customers will participate resulting in 26.2 GW.h and 4.6 MW of electric savings and 4.8 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 32% of targeted customers by the end of 2015/16.

The program is designed to reduce residential water heating energy consumption through the use of low flow, energy efficient plumbing fixtures. Customers are offered a free water and energy saver kit with program messaging focused on the energy and water benefits of energy efficient plumbing fixtures. The program offers three channels of participation: mail, targeted direct installation and a bulk mail or installation option for property managers of multi-unit residential facilities.

The target market includes all residential dwellings that use electricity or natural gas to heat water, totaling 515,000 customers.

A lack of awareness of the benefits of energy efficient plumbing fixtures and, for some customers, a perception that their fixtures are already energy efficient, combined with limited availability of Power Smart qualifying products at local retailers will limit customer adoption of the higher efficiency fixtures. Through advertising and the free kit offering, market acceptance of Power Smart plumbing fixtures will increase.

	2010/11 to 2014/15*	2015/16	Total to 2015/16
No. of Houses (annual)	140,247	29,000	**169,247**
Capacity Savings (MW)	3.8	0.8	**4.6**
Energy Savings (GW.h)	21.6	4.6	**26.2**
Natural Gas Savings (million m^3)	4.0	0.8	**4.8**
Utility Investment (Millions, 2015$)	$7.6	$2.1	**$9.7**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$7.6	$2.0	**$9.6**

Estimated Average Annual Bill Reduction per Kit (Electric): $25

Estimated Average Annual Bill Reduction per Kit (Natural Gas): $15

*Includes estimates for 2014/15

Refrigerator Retirement Program

The Refrigerator Retirement Program was launched in June 2011 and is scheduled to run until 2016/2017. In 2015/16, the program expects to retire 8,000 refrigerators and 3,000 freezers, resulting in 15.2 GW.h and 1.6 MW of electric savings. Combined with achievements to date, 46,017 customers will participate resulting in 59.9 GW.h and 5.9 MW of electric savings by the end of 2015/16. The program is forecast to reach 16% of targeted customers for fridges and 4% for freezers by the end of 2015/16.

The program is designed to reduce residential energy consumption through the removal of old, inefficient, and often nearly empty refrigerators and freezers. Customers can receive free in-home pick-up of qualifying working units plus a financial incentive for each unit. Customers will also save over $100 per year in electricity cost by removing these units. The program encourages customer to retire their secondary unit and not replace it in order to maximize savings.

The target market includes all single family residential homes, representing approximately 224,000 older second fridges and 222,000 older freezers.

Most customers do not know the costs of operating an underutilized refrigerator or freezer, and many lack assistance in removing the appliance from the home. Through the program, customers are made aware of the costs of their second appliance and the benefits of "retiring" it. The program makes "retiring" easy by providing a convenient in-home pickup service.

	2011/12 to 2014/15*	2015/16	Total to 2015/16
Total Participation (annual)	35,017	11,000	**46,017**
No. of Fridges (annual)	28,365	8,000	**36,365**
No. of Freezers (annual)	6,653	3,000	**9,653**
Capacity Savings (MW)	4.4	1.6	**5.9**
Energy Savings (GW.h)	44.7	15.2	**59.9**
Utility Investment (Millions, 2015$)	$7.0	$2.3	**$9.3**
Customer Investment (Millions, 2015$)	$3.0	$1.7	**$4.6**
Total DSM Investment (Millions, 2015$)	$9.9	$4.0	**$13.9**
Estimated Average Annual Bill Reduction per Customer (Electric) without fridge replacement: $100			
Estimated Average Annual Bill Reduction per Customer (Electric) without freezer replacement: $65			

*Includes estimates for 2014/15

Drain Water Heat Recovery Initiative

The Power Smart Drain Water Heat Recovery (DWHR) Initiative is a new initiative targeted to launch in the 2015/16 fiscal year. In 2015/16, program participation is expected to be 1,856, resulting in 1.9 GW.h and 0.3 MW of electric. The program is forecast to reach 80% of targeted customers by the end of 2015/16.

The initiative is designed to reduce energy consumption as it relates to electric water heating in the new home market.

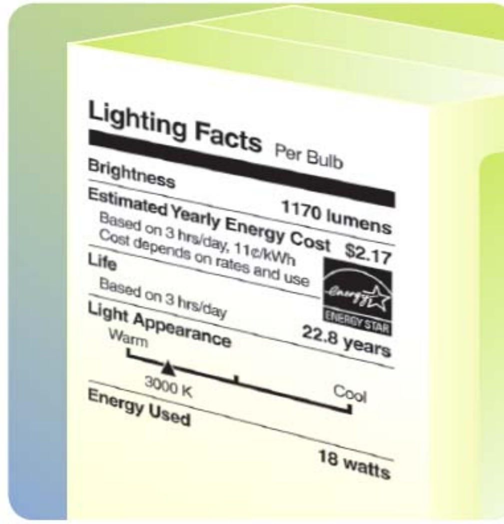
DWHR systems are typically installed on a section of a home's main drain stack usually found in the basement. The DWHR system recovers heat that would normally be lost when the drain water flows into the sewer system and transfers it to the fresh water going into the hot water tank. The end result is that the hot water tank uses less energy to heat incoming cold water. DWHR systems only save energy when hot water is flowing down the drain at the same time as fresh hot water is required (for example when taking a shower). DWHR systems are an excellent technology for large households whose primary method of washing is showering. DWHR systems can save approximately 25% of a customer's water heating energy consumption as it relates to showering.

The initiative is designed to overcome the one of the primary market barriers which is high cost. Manitoba Hydro has secured lower than average market pricing for the DWHR systems so that the above noted market sectors can install the technology at little to no cost. The low cost of the systems secured through the initiative allows Manitoba Hydro to provide an incentive to customers that would cover most if not all costs associated with installing a system.

	2014/15*	2015/16	Total to 2015/16
No. of Houses (annual)	0	1,856	**1,856**
Capacity Savings (MW)	0	0.3	**0.3**
Energy Savings (GW.h)	0	1.9	**1.9**
Utility Investment (Millions, 2015$)	$0.0	$0.6	**$0.6**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$0.0	$0.6	**$0.6**
Estimated Average Annual Bill Reduction per Customer (Electric): $70			

*Includes estimates for 2014/15

Residential LED Lighting Program



The Residential LED Lighting Program was launched in October 2014 and is scheduled to run until 2018/2019. In 2015/16, program participation is expected to be over 97,000 residential dwellings (over 390,000 LED bulbs) resulting in 12.7 GW.h and 4.0 MW of electric savings. Combined with achievements to date, program participation will be over 194,000 residential dwellings (over 720,000 LED bulbs) resulting in 23.1 GW.h and 7.3 MW of electric savings by the end of 2015/16. The program is expected to increase the socket penetration of screw-in LED bulbs in Manitoba by 4% by the end of 2015/16.

The program is designed to encourage residential customers to choose the most energy efficient lighting technology for each application within their home. The program aims to increase the adoption of Light Emitting Diode (LED) technology as a replacement for incandescent and halogen screw-in light bulbs.

The target market includes 465,000 residential dwellings and approximately 17 million screw-based sockets in which LED bulbs can be used. Although consumers are slowly moving toward replacing existing incandescent and halogen bulbs with LEDs as LED prices continue to decrease, the lack of awareness of the benefits and available variety of LED products remain significant barriers to widespread adoption.

	2014/15*	2015/16	Total to 2015/16
No. of Bulbs (annual)	330,658	392,724	**723,382**
Capacity Savings (MW)	3.3	4.0	**7.3**
Energy Savings (GW.h)	10.4	12.7	**23.1**
Utility Investment (Millions, 2015$)	$2.2	$2.6	**$4.8**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$2.2	$2.6	**$4.8**
Estimated Average Annual Bill Reduction per Bulb (Electric): $3			

*Includes estimates for 2014/15

Community Geothermal Program

The Power Smart Community Geothermal Program was launched in May 2013. In 2015/16, program participation is expected to be 220 systems, resulting in 3.8 GW.h and 1.9 MW of electric savings. The expected number of geothermal installations in 2015/16 has been decreased from those outlined in the 2014-2017 Power Smart Plan. The updated forecast reflects the number of geothermal systems which participating First Nation communities are forecasting to install during the year. Combined with achievements to date, 427 customers will participate resulting in 6.1 GW.h and 3.1 MW of electric savings by the end of 2015/16. The program is forecasted to reach 3% of targeted customers by the end of 2015/16.

The program is designed to reduce customers' electric space heating costs through the adoption of geothermal heat pump systems in First Nations communities. The program is designed to offer a customized approach for each community, with the assistance of AKI Energy, a non-profit social enterprise. To help

mitigate the high capital cost barrier, a third-party provider is contracted to conduct a feasibility study and to provide a quote on the bulk purchase of the heat pump units, including installation, resulting in a much lower per unit price than the current market average. Another component of the program includes creating job opportunities and training for First Nations to take part in the installation and the ongoing maintenance of the geothermal systems, with training funded by the First Nation. Manitoba Hydro provides technical guidance, assesses the energy bills to determine which homes would be the most suitable and economic for geothermal installations, and explores opportunities to further maximize the number of geothermal installations. Manitoba Hydro's PAYS Financing Program is utilized to enable community members to pay for the majority of the geothermal system through the energy savings that are realized by converting their heating/air conditioning systems to a geothermal system. For some homes that are close to being able to realize enough energy savings to finance the cost of the geothermal system through the PAYS Financing Program, Manitoba Hydro will provide financial support.

It is anticipated that the Community Geothermal Program will increase the adoption of heat pumps in First Nations communities as the total cost of the system will be substantially reduced and the loan will be paid through the energy savings.

	2013/14 to 2014/15*	2015/16	Total to 2015/16
No. of Geothermal Systems (annual)	207	220	**427**
Capacity Savings (MW)	1.2	1.9	**3.1**
Energy Savings (GW.h)	2.3	3.8	**6.1**
Utility Investment (Millions, 2015$)	$1.5	$1.5	**$3.0**
Customer Investment (Millions, 2015$)	$3.1	$2.5	**$5.7**
Total DSM Investment (Millions, 2015$)	$4.6	$4.1	**$8.6**
Estimated Average Annual Bill Reduction per Customer (Electric): $1,095			

*Includes estimates for 2014/15

Manitoba Hydro offers the following convenient financing programs to support energy efficiency upgrades by allowing customers to finance initial Power Smart project costs and pay the costs back on their monthly Manitoba Hydro bill.

Power Smart Residential Loan

The Power Smart Residential Loan (PSRL) was launched in March 2001. In 2015/16, the program is expected to finance energy efficient upgrades for 5,700 homes, achieving 0.5 GW.h and 0.3 MW of electric savings and 0.3 million cubic metres of natural gas savings. Combined with achievements to date, 86,992 homes will be retrofitted, resulting in 11.1 GW.h and 6.2 MW of electric savings and 15.8 million cubic metres of natural gas savings by the end of 2015/16.

The PSRL was designed to provide customers with convenient on-bill financing to assist them in making their home more energy efficient. Under the PSRL, the following energy efficiency improvements can be made to the home: insulation, ventilation equipment, air leakage sealing, windows and doors, and space and water heating equipment. Participants can borrow up to $7,500 ($5,500 for natural gas furnaces) and repay the amount on their energy bill over a term of up to 5 years (up to 15 years for natural gas furnaces and boilers). The target market consists of electric and natural gas homeowners in Manitoba.

	2001/02 to 2014/15*	2015/16	Total to 2015/16
No. of Loans (annual)	81,292	5,700	**86,992**
Capacity Savings (MW)	5.9	0.3	**6.2**
Energy Savings (GW.h)	10.6	0.5	**11.1**
Natural Gas Savings (million m^3)	15.5	0.3	**15.8**
Average Loan Amount: $4,640			

*Includes estimates for 2014/15

Power Smart PAYS Financing

The Power Smart Pay-As-You-Save (PAYS) Financing Program was launched in November 2012. In 2015/16, the program is expected to finance energy efficient upgrades for 336 homes, achieving 0.3 GW.h and 0.1 MW of electric savings. Combined with achievements to date, 919 homes will be retrofitted, resulting in 1.8 GW.h and 0.5 MW of electric savings by the end of 2015/16.

The program offers low-interest on-bill financing for energy efficient upgrades. Financing is available over a term of up to 25 years (depending on the technology financed) with a 5-year fixed interest rate. Energy efficient upgrades that may qualify for financing are:

- Space heating equipment:
    - High efficiency natural gas furnaces;
    - Natural gas boilers (minimum AFUE of 85%);
    - Geothermal heat pump systems;
- Insulation upgrades;
- Drain water heat recovery systems;
- WaterSense-labeled toilets (in conjunction with energy efficient equipment).

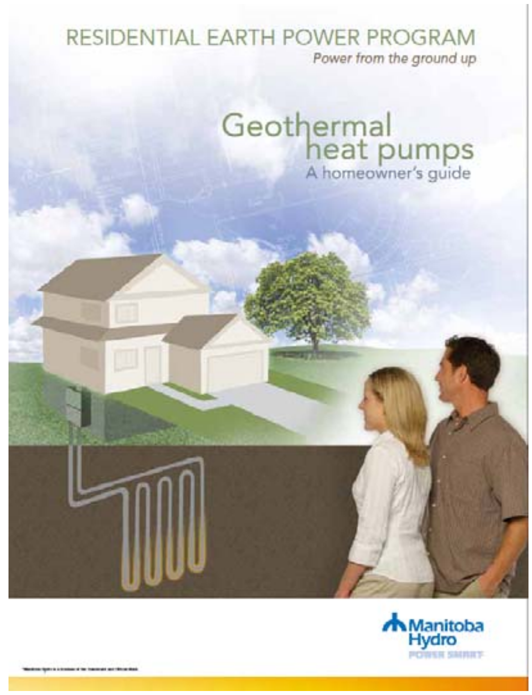
The target market consists of all electric and natural gas customers in Manitoba. This offering complements and supports existing incentive-based programs by assisting customers in managing the installation cost of their upgrade. To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing payment, thereby resulting in an energy bill that is less than or equal to the total bill prior to the retrofit. PAYS financing also differs from Manitoba Hydro's other financing programs in that the loan is transferable between homeowners when a property is sold, and is transferable from a landlord to a tenant where the tenant is responsible for paying the energy bill.

	2012/13 to 2014/15*	2015/16	Total to 2015/16
No. of Loans (annual)	583	336	**919**
Capacity Savings (MW)	0.4	0.1	**0.5**
Energy Savings (GW.h)	1.6	0.3	**1.8**
Natural Gas Savings (million m^3)	0.0	0.0	**0.0**
Average Loan Amount: $6,630			

*Includes estimates for 2014/15

Residential Earth Power Loan

The Residential Earth Power Loan (REPL) was launched in April 2002. In 2015/16, program participation is expected to be 130 loans, resulting in 0.7 GW.h and 0.3 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 1,388 customers will participate resulting in 16.3 GW.h and 4.9 MW of electric savings and 3.0 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 0.5% of targeted customers by the end of 2015/16.



The loan is designed to support the adoption of geothermal heat pump technology Although more expensive to install, geothermal heat pump systems offer significant electricity savings, thereby reducing customers' monthly utility bills. The convenience and flexibility of the on-bill REPL reduces the financial barrier that exists when installing a geothermal heat pump system. The program was also designed to build awareness of emerging technologies and foster new, growing industries that utilize these technologies through educational materials, technical support, and training workshops. Solar hot water systems were added as an eligible technology in 2010.

Customers are eligible for up to $20,000 in financing for installing geothermal heat pump systems or $7,500 in financing for installing solar domestic water heating systems. The financial terms include a 5-year fixed interest rate over a 15-year maximum amortization term. The interest rate for the balance of the financing period is established at Manitoba Hydro's cost of borrowing at the time the fixed interest rate term expires.

	2002/03 to 2014/15*	2015/16	Total to 2015/16
No. of Loans (annual)	1,258	130	**1,388**
Capacity Savings (MW)	4.6	0.3	**4.9**
Energy Savings (GW.h)	15.6	0.7	**16.3**
Natural Gas Savings (million m^3)	2.9	0.1	**3.0**
Average Loan Amount: $18,831			

*Includes estimates for 2014/15

Commercial

Manitoba Hydro offers a number of innovative programs, using a variety of market intervention tools including but not limited to, incentives, financing, technical assistance, industry education and training, to address opportunities in the commercial market.

Commercial Lighting Program

The Commercial Lighting Program was launched in May 1992. In 2015/16, program participation is expected to be 767 projects, resulting in 39.3 GW.h and 10.3 MW of electric savings. Combined with achievements to date, 14,671 projects will be completed resulting in 458.3 GW.h and 91.9 MW of electric savings by the end of 2015/16. The program is forecast to reach 28% of the target market by the end of 2015/16.

The program is designed to reduce electricity consumption by accelerating the acceptance and adoption of energy efficient lighting technologies in Manitoba. Commercial, industrial, and agricultural customers are encouraged to install qualifying energy efficient lighting technologies in their facilities to reduce energy bills, improve the quality of lighting, as well as increase safety, security, and productivity. The program offers support through the use of educational materials, information seminars, and financial incentives.

The target market consists of all existing commercial, industrial, and agricultural buildings with inefficient lighting installations in Manitoba, where lighting systems operate a minimum of 2,000 hours per year. Lighting systems that operate between 1,000 to 1,999 hours per year may qualify for prorated incentives. New construction projects that do not meet the New Buildings Program eligibility criteria may qualify. The estimated market size is 52,500 lighting projects. Many energy efficient lighting options have higher initial capital costs, and oftentimes customers lack awareness of the technologies available and the non-energy related benefits of energy efficient lighting, thereby creating a barrier to the adoption of higher efficiency systems. In addition, many customers operate in commercial lease space where the person making decisions related to lighting upgrades may not pay the utility bill and therefore, does not realize the direct financial return. Strategies in place to address these market barriers include financial incentives, education and training, as well as hands on technical and customer service support.

	1992/93 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	13,904	767	**14,671**
Capacity Savings (MW)	81.5	10.3	**91.9**
Energy Savings (GW.h)	419.0	39.3	**458.3**
Utility Investment (Millions, 2015$)	$103.4	$8.9	**$112.3**
Customer Investment (Millions, 2015$)	$39.5	$4.7	**$44.2**
Total DSM Investment (Millions, 2015$)	$142.8	$13.7	**$156.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $232			

*Includes estimates for 2014/15

LED Roadway Lighting Conversion Program

The Power Smart LED Roadway Lighting Conversion Program was launched in June 2015 and is scheduled to run until 2020/21. In 2015/16, program participation is expected to be 27,863 conversions, resulting in 10.8 GW.h and 1.6 MW of electric savings. Combined with achievements to date, 33,108 conversions will take place resulting in 12.8 GW.h and 2.1 MW of electric savings by the end of 2015/16. The program is forecast to reach 25% of targeted customers by the end of 2015/16.

The program is designed to convert existing High Pressure Sodium (HPS) roadway, decorative, lane and area lights to Light Emitting Diode (LED) lights over a 6-year period. Manitoba Hydro provides energy and maintenance services to over 130,000 roadway lights across the Province of Manitoba

The current roadway lighting technology is High Pressure Sodium (HPS), which produces a yellow/orange light and has a four-year lamp life. The wattages range from 70 to 1,000 and these light fixtures were originally installed in 1991 under a past Power Smart Roadway Lighting Conversion Program to replace Mercury Vapour and Incandescent lighting.

In addition to energy savings, LED roadway lighting has a significantly longer life than HPS lighting, quick turn on and off, and improved contrast and colour rendering due to their white light output. LED lights also provide the added benefit of directing the light downward onto the roadway increasing the amount of light on the road and improving drivers' visibility.

	2014/15*	2015/16	Total to 2015/16
No. of Conversions (annual)	5,245	27,863	**33,108**
Capacity Savings (MW)	0.5	1.6	**2.1**
Energy Savings (GW.h)	2.1	10.8	**12.8**
Utility Investment (Millions, 2015$)	$2.0	$11.0	**$13.0**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$2.0	$11.0	**$13.0**

*Includes estimates for 2014/15

Commercial Building Envelope - Windows Program

The Commercial Building Envelope (Windows) Program was launched in 1995. In 2015/16, program participation is expected to be 225 projects, resulting in 2.1 GW.h and 1.0 MW of electric savings and 0.3 million cubic metres of gas savings. Combined with achievements to date, participation will be 1,760 projects resulting in 20.8 GW.h and 8.6 MW of electric savings and 2.6 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 7% of the total potential market by the end of 2015/16.

The program is designed to improve building envelope performance and reduce energy consumption through the installation of high performance windows in existing buildings. The target market consists of all existing commercial customers, primarily focused on sectors such as multi-unit residential facilities, schools, hotels/motels, personal care homes, and health care facilities. The program targets facilities planning to replace existing windows, thus presenting an economic opportunity to install higher efficiency Power Smart qualifying windows at the time of replacement.

Market barriers include the incremental product cost of high performance windows, along with a lack of awareness of the significant potential energy savings and other non-energy benefits. Providing financial incentives to help offset incremental material costs, working closely with local fabricators and window suppliers and contractors, while promoting the benefits of high performance windows is effectively addressing these barriers.

It is estimated that there are approximately 750 potential window replacement projects in Manitoba each year, of a total market of 27,000 potential projects. To date, over 1,500 energy efficient window projects have been completed.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	1,535	225	**1,760**
Capacity Savings (MW)	7.5	1.0	**8.6**
Energy Savings (GW.h)	18.7	2.1	**20.8**
Natural Gas Savings (million m^3)	2.3	0.3	**2.6**
Utility Investment (Millions, 2015$)	$15.7	$1.7	**$17.4**
Customer Investment (Millions, 2015$)	$0.4	$0.3	**$0.6**
Total DSM Investment (Millions, 2015$)	$16.1	$2.0	**$18.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $618			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $674			

*Includes estimates for 2014/15

Commercial Building Envelope - Insulation Program

The Commercial Building Envelope (Insulation) Program was launched in April. In 2015/16, program participation is expected to be 230 projects, resulting in 2.2 GW.h and 1.0 MW of electric savings and 0.8 million cubic metres of natural gas savings. Combined with achievements to date, participation will be 1,750 projects resulting in 32.1 GW.h and 14.7 MW of electric savings and 12.0 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 12% of the total potential market by the end of 2015/16.

The program is designed to improve building envelope performance and reduce energy consumption by upgrading insulation levels in roof and wall areas of existing buildings.

The target market is comprised of all commercial customers with insulation levels that do not meet Power Smart levels. The program targets facilities planning to undergo extensive repairs to existing roofs and walls, presenting an economic opportunity to improve existing insulation levels at the time of renovation.

Market barriers include the incremental product cost of insulation upgrades and a lack of awareness of the significant potential energy savings and other non-energy benefits associated with upgraded insulation levels. Providing financial incentives to help offset incremental material costs and promoting the benefits of better insulated buildings is effectively addressing these barriers.

It is estimated that there are approximately 400 potential insulation replacement projects in Manitoba each year, of a total market of 15,000 potential projects.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	1,520	230	**1,750**
Capacity Savings (MW)	13.7	1.0	**14.7**
Energy Savings (GW.h)	29.9	2.2	**32.1**
Natural Gas Savings (million m^3)	11.1	0.8	**12.0**
Utility Investment (Millions, 2015$)	$17.0	$2.1	**$19.1**
Customer Investment (Millions, 2015$)	$10.1	$0.3	**$10.4**
Total DSM Investment (Millions, 2015$)	$27.1	$2.5	**$29.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $85			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $199			

*Includes estimates for 2014/15

Commercial Geothermal Program

The Commercial Geothermal Program was launched in 2007. In 2015/16, program participation is expected to be 23 customers, resulting in 2.4 GW.h and 1.2 MW of electric savings. Combined with achievements to date, 163 customers will participate resulting in 44.6 GW.h and 17.3 MW of electric savings by the end of 2015/16. The program is forecast to reach 7% of targeted customers by the end of 2015/16.

The program is designed to encourage the installation of geothermal heat pumps in electrically heated commercial buildings. The target market consists of existing commercial buildings that use conventional electric technologies for space heating at or approaching end of life. New buildings in electric heat only territories are also targeted. The high capital cost of installing a geothermal heat pump system, combined with the available supply of qualified installers and contractors in some regions of the province; challenging drilling and trenching conditions due to varying geological conditions; limited land area of many properties to accommodate the loop installation; and the proximity to the ground loop of underground facilities and services (water and sewer lines that may freeze, etc.) can make choosing geothermal as a heating/cooling option more challenging for the customer. Through the program, customers are provided with information on how the geothermal heat pump technology works, the energy savings available, and other benefits to increase understanding and acceptance of the technology. Financial incentives are offered to help offset the higher capital costs of the system, and as well, to support feasibility studies, ensuring the installation of a geothermal heat pump system is an economic option for the customer. Benefits of geothermal systems and program opportunities are communicated through the broad network of engineers, architects, consultants, contractors, and trade allies in Manitoba who have established relationships with the commercial and industrial customer base.

New to the 2015 fiscal period will be a comprehensive training initiative for the geothermal industry. Prior to implementing increased incentives for the program, training will be offered on design and sizing of loop fields and mechanical systems to further educate designers and increase the longevity of these heating systems.

	2007/08 to 2014/15*	2015/16	Total to 2015/16
No. of Buildings (annual)	140	23	**163**
Capacity Savings (MW)	16.1	1.2	**17.3**
Energy Savings (GW.h)	42.2	2.4	**44.6**
Utility Investment (Millions, 2015$)	$6.0	$0.5	**$6.6**
Customer Investment (Millions, 2015$)	$20.5	$1.1	**$21.5**
Total DSM Investment (Millions, 2015$)	$26.5	$1.6	**$28.1**

Estimated Average Annual Bill Reduction per Customer (Electric): $6,256

*Includes estimates for 2014/15

Commercial HVAC Program – Boilers

The Commercial HVAC Program for Boilers was launched in April 2006 and is scheduled to run until 2017/18. In 2015/16, program participation is expected to be 117 boilers, resulting 1.0 million cubic metres of gas savings. Combined with achievements to date, 1,194 boilers will be installed resulting 11.9 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 17% of targeted customers by the end of 2015/16. In addition, the Program will pursue provincial regulations requiring all boilers installed in new buildings within Manitoba to be condensing by April 1, 2017.

The program is designed to transform the commercial boiler market in Manitoba by increasing awareness and adoption of energy efficient condensing and near-condensing boilers. Energy efficient boilers offer significant natural gas savings, reducing customers' monthly utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives ranging from $2/MBH (thousands of BTUs per hour) to $8/MBH are provided for qualifying systems.

The program is designed to build market acceptance prior to, and thereby ensuring the successful adoption of, Natural Resources Canada's (NRCan) minimum efficiency regulations for commercial boilers, which are currently under development.

The primary target market consists of commercial buildings with existing heating equipment at or approaching end of life. On average, 285 commercial boilers are installed annually in existing buildings. Boiler replacements are not likely to occur until existing equipment is near their end of life and are often completed in an emergency situation during the heating season. Purchase decisions are therefore made with limited lead time and primarily based upon the initial capital cost, not considering the annual operating costs of the system over its 25 year life. Condensing or near-condensing natural gas boilers are also more expensive to install than conventional boilers, and require modifications to the ventilation system. Financial incentives combined with information on the lifecycle cost advantage of energy efficient systems are in place to address these market barriers.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Boilers (annual)	1,077	117	**1,194**
Natural Gas Savings (million m^3)	10.9	1.0	**11.9**
Utility Investment (Millions, 2015$)	$11.7	$1.1	**$12.7**
Customer Investment (Millions, 2015$)	$8.1	$0.6	**$8.7**
Total DSM Investment (Millions, 2015$)	$19.8	$1.7	**$21.4**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $2,193			

*Includes estimates for 2014/15

Commercial HVAC Program - Chillers

The Power Smart Commercial HVAC Program for Chillers was launched in April 2006 and is scheduled to run until 2021/22. In 2015/16, program participation is expected to be 24 chillers, resulting in 5.1 GW.h of electric savings. Combined with achievements to date, 116 chillers will be installed resulting in 19.8 GW.h of electric savings by the end of 2015/16. The program is forecast to reach 27% of targeted customers by the end of 2015/16.

The program is designed to transform the commercial chiller market in Manitoba by increasing awareness and adoption of energy efficient water-cooled chillers and variable speed drive retrofits. Energy efficient chillers offer significant electricity savings, reducing customers' utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives of $56 per ton are provided for qualifying units.

Typically, chillers have a 30 year life and are replaced when the refrigerant is required to be changed or when the equipment is reaching end of life. The primary target market for chillers are large, older, commercial buildings, consisting primarily of large offices, large multi-residential, hospitals and large educational facilities. The high initial cost of chiller systems combined with the tendency for customers to emphasize the initial investment cost over operating efficiency or life cycle costs when making their purchase decision, has created a barrier for the higher efficiency systems. Offering aggressive financial incentives while promoting the lifecycle cost advantage is effectively addressing these barriers and ensuring that efficient chillers are chosen at the time of existing equipment replacement.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Chillers (annual)	92	24	**116**
Capacity Savings (MW)	0.0	0.0	**0.0**
Energy Savings (GW.h)	14.7	5.1	**19.8**
Utility Investment (Millions, 2015$)	$2.2	$0.5	**$2.7**
Customer Investment (Millions, 2015$)	$2.2	$0.4	**$2.5**
Total DSM Investment (Millions, 2015$)	$4.4	$0.8	**$5.2**
Estimated Average Annual Bill Reduction per Customer (Electric): $8,115			

*Includes estimates for 2014/15

Commercial HVAC Program - C02 Sensors

The Commercial HVAC Program for CO_2 sensors was launched in April 2009 and is scheduled to run until 2023/24. In 2015/16, program participation is expected to be 112 sensors, resulting in 0.2 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 493 sensors will be installed resulting in 0.7 GW.h and 0.3 MW of electric savings and 0.7 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 9% of targeted customers by the end of 2015/16.

The program is designed to increase the awareness and adoption of CO_2 sensors in commercial facilities. CO_2 sensors reduce energy consumption by matching ventilation supply to occupant demand, reducing customers' monthly utility bills. CO_2 sensors also improve occupant comfort by providing more consistent air quality and can extend the life of heating and cooling equipment by putting less demand on these systems.

The target market for CO_2 sensors consists of over-ventilated commercial facilities with variable occupancy and that have, or are considering installing, Direct Digital Control systems or rooftop units to control heating, cooling, and ventilation. Installations typically occur when other major renovations are being made to the ventilation system. It is estimated that a total of 279 potential sensor installations in Manitoba exists each year. The program is forecasted to achieve CO_2 Sensor installation in 42% of the targeted ventilation upgrades in 2015/16.

CO_2 sensors are not required in commercial building operation and therefore are often one of the first retrofit measures to be discarded in the event of budgetary constraints. Customers also tend to be unfamiliar with the operation of their ventilation systems and may be unaware when a building is over-ventilated. Offering aggressive financial incentives while promoting the lifecycle cost advantage and improved ventilation benefits, is effectively addressing these barriers.

	2009/10 to 2014/15*	2015/16	Total to 2015/16
No. of Sensors (annual)	381	112	**493**
Capacity Savings (MW)	0.2	0.1	**0.3**
Energy Savings (GW.h)	0.4	0.2	**0.7**
Natural Gas Savings (million m^3)	0.6	0.1	**0.7**
Utility Investment (Millions, 2015$)	$0.2	$0.2	**$0.4**
Customer Investment (Millions, 2015$)	$0.2	$0.0	**$0.3**
Total DSM Investment (Millions, 2015$)	$0.4	$0.2	**$0.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $83			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $155			

*Includes estimates for 2014/15

Commercial HVAC Program - Water Heaters

The Power Smart Commercial Water Heater Program is a proposed program targeted to launch in the 2015/16 fiscal year and is scheduled to run until 2025/26. In 2015/16, program participation is expected to be 25 water heaters, resulting in 0.04 million cubic metres of gas savings. The program is forecast to reach 0.6% of targeted customers by the end of 2015/16.

The end user target market is commercial buildings with high levels of domestic hot water consumption where the current water heating system is nearing end of life. The total retrofit market potential is approximately 350 water heater installs in 2015.

Prescriptive product rebates will aid in addressing high initial cost and long payback barriers of condensing water heaters. Advertising and promotional activities will increase consumer and contractor awareness of the Program throughout 2015/16, resulting in a slow ramp-up of participation during the first few Program years. In the Program's final year, rebates for condensing storage and tankless water heaters are expected to help achieve 75% annual market penetration and will be available until a federal regulation takes effect.

Rebate amounts will be dependent on the btu/h heating capacity of the water heater(s) and whether it is a tank or tankless model. Eligible water heaters are between 75,000 and 500,000 btu/h input capacity.

Upgrading to a condensing water heater can reduce energy use by 28%, saving the customer an average of $600 per year in energy costs. Rebates represent 34% of the current estimated incremental product, material, and labour cost and will help reduce a customer's payback from 7.1 to 4.8 years on average. Customers who require multiple tanks will benefit from a shorter payback period due to economies of scale on labour, venting, and product costs. Further, many electric customers with multiple tanks may achieve the additional benefit of being able to reduce the overall number of water heaters as they change from an electric to a gas fuel source. Finally, it is anticipated the program will significantly increase the market penetration of technology thus driving down incremental costs and improving customer payback.

The Program will support future regulations by advancing market acceptance of condensing water heating technology in Manitoba. The Program will prepare the market for a condensing water heater regulation by educating customers, contractors, and distributors about the benefits of condensing water heaters. In addition, rebates will increase market penetration by reducing capital costs.

	2014/15*	2015/16	Total to 2015/16
No. of Water Heaters (annual)	0	25	**25**
Natural Gas Savings (million m^3)	0.0	0.0	**0.0**
Utility Investment (Millions, 2015$)	$0.0	$0.1	**$0.1**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$0.0	$0.1	**$0.2**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $376			

*Includes estimates for 2014/15

Commercial Custom Measures Program

The Power Smart Commercial Custom Measures Program was launched in 2006. In 2015/16, program participation is expected to be 9 projects, resulting in 0.6 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 92 projects will participate resulting in 25.0 GW.h and 2.2 MW of electric savings and 1.6 million cubic metres of natural gas savings by the end of 2015/16.

The program is designed to encourage commercial customers to explore and implement energy efficient upgrades of their operations or facilities. This program offers the opportunity to explore customer-specific and unique projects or newer technologies that are not currently eligible under the other Power Smart for Business Program offerings. Technologies and projects may include digital control systems, hot water and space heating equipment, waste energy recovery systems, variable speed drive systems, and solar air and water heating systems. The program provides incentives to help cover the cost of feasibility studies that are often required for larger projects and newer or emerging technologies, and implementation incentives based on projected savings from the project.

The program targets all commercial customers planning new construction, renovation or expansion projects. Often the high incremental cost of energy efficient technologies and systems, customer uncertainty of payback, and lack of awareness of energy efficient alternatives limit a customer's propensity to invest in an energy efficient project. The Custom Measures Program addresses these barriers by promoting new and innovative technologies, by offering a feasibility study incentive to provide confidence in energy savings estimates, and by offering incentives to help reduce the implementation cost.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	83	9	**92**
Capacity Savings (MW)	2.0	0.1	**2.2**
Energy Savings (GW.h)	24.4	0.6	**25.0**
Natural Gas Savings (million m^3)	1.5	0.1	**1.6**
Utility Investment (Millions, 2015$)	$4.6	$0.5	**$5.0**
Customer Investment (Millions, 2015$)	$12.1	$0.5	**$12.6**
Total DSM Investment (Millions, 2015$)	$16.7	$1.0	**$17.6**

Estimated Average Annual Bill Reduction per Customer (Electric): $7,061

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $6,582

*Includes estimates for 2014/15

Commercial Building Optimization Program

The Power Smart Commercial Building Optimization Program (CBOP) was, launched in 2006. In 2015/16, program participation is expected to be 2 buildings, resulting in 0.3 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 18 buildings will participate resulting in 3.6 GW.h and 0.6 MW of electric savings and 0.7 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 4% of targeted customers by the end of 2015/16.

The program is designed to encourage commercial customers with existing buildings to engage in an assessment and adjustment process known as retrocommissioning (RCx) to help return their buildings' mechanical systems to their designed operating characteristics and even further optimize their operation to save energy and improve occupant comfort. The program focuses on identifying non-capital intensive energy conservation opportunities with relatively short payback periods and offers incentives that cover a portion of the cost for hiring an RCx agent and implementing the energy efficient measures identified through the investigation process. In 2015/16, the program is expected to support the retrocommissioning of 2 buildings, achieving 0.3 GW.h and 0.1 MW of electric savings and 80,000 cubic metres of natural gas savings.

The market consists of existing commercial buildings larger than 50,000 square feet and between 2 and 25 years of age with direct digital control systems and functioning heating, ventilating and air conditioning mechanical systems. There are approximately 470 buildings in this market, however there are significant barriers that must be overcome to reach these customers including lack of experience and availability of RCx providers in Manitoba, lack of customer awareness of the cost-saving benefits of RCx, and lack of customer time and competing priorities for capital to invest in energy efficiency projects. The program addresses these barriers by providing training and information sessions for potential and existing RCx providers, by promoting RCx at relevant industry events, and by offering incentives to reduce the capital cost and payback cycle of the RCx process.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Buildings (annual)	16	2	**18**
Capacity Savings (MW)	0.5	0.1	**0.6**
Energy Savings (GW.h)	3.3	0.3	**3.6**
Natural Gas Savings (million m^3)	0.6	0.1	**0.7**
Utility Investment (Millions, 2015$)	$2.3	$0.4	**$2.7**
Customer Investment (Millions, 2015$)	$0.2	$0.1	**$0.2**
Total DSM Investment (Millions, 2015$)	$2.4	$0.5	**$2.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $9,276			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $11,313			

*Includes estimates for 2014/15

New Buildings Program

The New Buildings Program was launched in 2010. In 2015/16, program participation is expected to be 40 new buildings, resulting in 14.0 GW.h and 4.2 MW of electric savings and 0.4 million cubic metres of gas savings. Combined with achievements to date, 96 new buildings will participate resulting in 29.6 GW.h and 7.8 MW of electric savings and 3.4 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 20% market penetration of the new construction market in 2015/16.

The program is designed to transform the commercial new construction industry in preparation for pending building codes which will require significant improvements in overall building energy efficiency. The program offers technical assistance and financial incentives for customers designing and constructing new, energy efficient commercial buildings.

The first version of the program aimed to prepare the Manitoba commercial building industry for the province's adoption of the National Energy Code of Canada for Buildings (NECB) 2011. Fifty one buildings have been completed through this program and 70 applicants are currently in design or under construction. As of December 1, 2014, all commercial buildings in Manitoba must now adhere to the province's version of the NECB called the Manitoba Energy Code for Buildings (MECB). Since the new code has come into force, a second version of New Buildings Program is available for projects bound by the new set of requirements. To qualify as an official Power Smart Building, projects must be designed with an energy target that is at least 10% better than a standard building. Financial incentives range from \$0.50/ ft^2 to \$2.00/ft^2 depending on the project's overall energy target. An Energy Modeling Assistance Incentive of up to \$10,000 is also available to encourage the use of energy modeling early in a building's design process and to help develop the local energy modeling industry in support of the Power Smart and the MECB.

The target market is all new commercial buildings that are bound by the requirements of the MECB. The industry faces fundamental changes to the current methods of designing, constructing, and commissioning commercial buildings. Manitoba Hydro also worked closely with the Province's Green Building Coordination Team to develop the Green Building Policy for Government of Manitoba Funded Projects. This policy ensures the Province's investments in new construction will help transform the local market and will help build industry capacity within Manitoba.

	2009/10 to 2014/15*	2015/16	Total to 2015/16
No. of Buildings (annual)	56	40	**96**
Capacity Savings (MW)	3.6	4.2	**7.8**
Energy Savings (GW.h)	15.7	14.0	**29.6**
Natural Gas Savings (million m^3)	3.0	0.4	**3.4**
Utility Investment (Millions, 2015$)	$6.0	$3.8	**$9.8**
Customer Investment (Millions, 2015$)	$8.1	$8.9	**$17.1**
Total DSM Investment (Millions, 2015$)	$14.1	$12.7	**$26.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $21,363			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $2,429			

*Includes estimates for 2014/15

Commercial Refrigeration Program

The Commercial Refrigeration Program was launched in 2006. In 2015/16, program participation is expected to be 310 projects, resulting in 9.5 GW.h and 1.1 MW of electric savings. Combined with achievements to date, participation will be 2,135 projects resulting in 58.4 GW.h and 8.1 MW of electric savings by the end of 2015/16. The program is forecast to reach 48% of targeted customers by the end of 2015/16.

The program is designed to encourage commercial customers to reduce energy consumption by providing over 15 different product incentives for energy efficient upgrades to refrigeration display cases, walk-in boxes, mechanical rooms, and lighting. Savings are achieved by providing customers with information about best practices and maintenance, promoting energy efficient refrigeration technologies, and optimizing the operation of new and existing refrigeration equipment. .

The target market is commercial customers with foodservice refrigeration equipment, primarily grocery, retail, and convenience stores. Many of the qualifying energy efficient refrigeration systems have higher incremental costs, and equipment upgrade decisions are sometimes based on aesthetics over energy efficiency. Offering financial incentives to lower incremental costs and promoting the energy and associated bill savings along with non-energy benefits of efficient refrigeration systems, such as increased comfort in refrigeration aisles for both customers and employees, reduced product spoilage, and extended equipment life for refrigeration motors and compressors, is effectively addressing these barriers.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
No. of Locations (annual)	1,825	310	**2,135**
Capacity Savings (MW)	7.0	1.1	**8.1**
Energy Savings (GW.h)	48.9	9.5	**58.4**
Utility Investment (Millions, 2015$)	$4.2	$0.8	**$5.0**
Customer Investment (Millions, 2015$)	$3.9	$0.1	**$4.0**
Total DSM Investment (Millions, 2015$)	$8.1	$0.9	**$9.0**
Estimated Average Annual Bill Reduction per Customer (Electric): $436			

*Includes estimates for 2014/15

Commercial Kitchen Appliance Program

The Commercial Kitchen Appliances Program was launched in 2008 and it is scheduled to run until 2017/18. In 2015/16 alone, the program is expected to support the installation of 970 appliances, achieving 0.9 GW.h and 0.2 MW of electric savings and 0.3 million cubic metres of natural gas savings. Combined with savings achieved to date, the program is expected to achieve achieving 2.4 GW.h and 0.4 MW of electric savings and 0.8 million cubic metres of natural gas savings by the end of 2015/16. The program is forecast to reach 61% of targeted customers by the end of 2015/16.

The program is designed to encourage customers to choose ENERGY STAR steam cookers (gas and electric) and ENERGY STAR deep fat fryers (gas only) when replacing commercial appliances. The target consists of restaurants and foodservice establishments with either gas or electric commercial kitchen appliances. ENERGY STAR qualified appliances have a higher initial cost to purchase and many customers are not aware that using ENERGY STAR appliances can decrease operating and maintenance costs and improve food quality. Providing financial incentives and promoting the various energy and non-energy benefits of ENERGY STAR kitchen appliances is effectively addressing these market barriers.

In August 2014, the Commercial Kitchen Appliances Program added low-flow pre-rinse spray valves to its portfolio to help foodservice establishments reduce their energy and water use. Spray valves are typically used by food processing facilities, restaurants, hotels, hospitals, personal care homes, and schools to rinse leftover food and grease off of plates, pots, and pans prior to putting them in the dishwasher. Although an important part of the dishwashing process, this technology can consume large quantities of water and energy (used to heat the water). The spray valve(s) and installation are free of charge to the customer.

	2008/09 to 2014/15*	2015/16	Total to 2015/16
No. of Appliances (annual)	716	970	**1,686**
Capacity Savings (MW)	0.2	0.2	**0.4**
Energy Savings (GW.h)	1.6	0.9	**2.4**
Natural Gas Savings (million m^3)	0.5	0.3	**0.8**
Utility Investment (Millions, 2015$)	$0.7	$0.3	**$0.9**
Customer Investment (Millions, 2015$)	$0.1	$0.0	**$0.2**
Total DSM Investment (Millions, 2015$)	$0.8	$0.3	**$1.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $238			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $136			

*Includes estimates for 2014/15

Network Energy Management Program

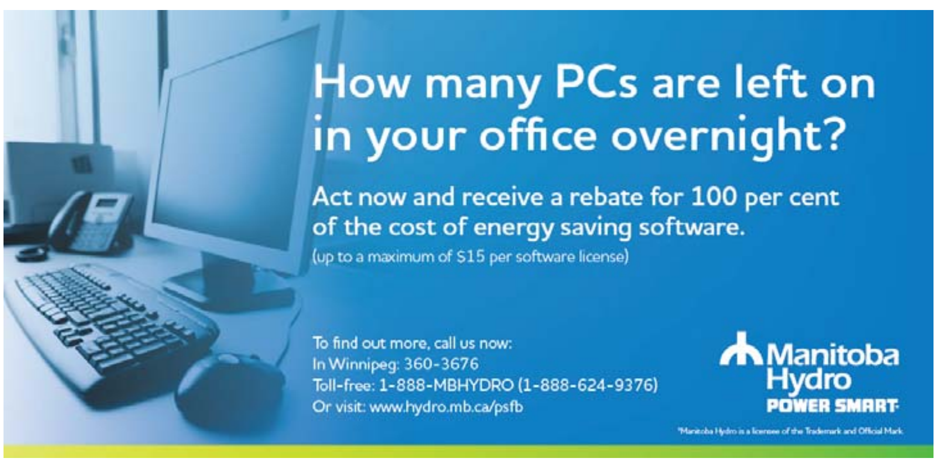
The Network Energy Management Program was launched in 2009. In 2015/16, program participation is expected to be 1,932 software licenses, resulting in 0.3 GW.h of electric savings. Combined with achievements to date, participation will be 7,278 software licenses resulting in 1.2 GW.h and 0.3 MW of electric savings by the end of 2015/16. The program is forecast to reach 2% of targeted customers by the end of 2015/16.

The program is designed to encourage customers to install program-approved software that conserves energy by sending personal computers (PCs) into a mode that consumes less energy when they are not in use. The program is aimed at commercial organizations that manage a network of PCs.

The target market is comprised of approximately 2,500 physical locations in the school/college and office sectors, representing approximately 300,000 PCs. Installation, configuration, and testing of this new software on existing networks can require a significant time investment. Although management may realize operational cost savings, IT staff are often cautious when implementing software that they perceive may in any way restrict their ability to access individual PCs remotely to perform maintenance and system upgrades. The program provides financial incentives and promotes the product benefits through direct marketing to both management and IT staff in order to address these barriers to adoption.

	2009/10 to 2014/15*	2015/16	Total to 2015/16
No. of Licenses (annual)	5,346	1,932	**7,278**
Capacity Savings (MW)	0.2	0.0	**0.3**
Energy Savings (GW.h)	0.9	0.3	**1.2**
Utility Investment (Millions, 2015$)	$0.3	$0.1	**$0.3**
Customer Investment (Millions, 2015$)	$0.1	$0.0	**$0.1**
Total DSM Investment (Millions, 2015$)	$0.4	$0.1	**$0.4**
Estimated Average Annual Bill Reduction per Customer (Electric): $3,414			

*Includes estimates for 2014/15



Internal Retrofit Program

The Internal Retrofit Program (IRP) was launched in 1993. In 2015/16, program participation is expected to be 23 projects, resulting in 0.8 GW.h and 0.2 MW of electric savings. Combined with achievements to date, participation will be 1,368 projects resulting in 67.2 GW.h and 14.2 MW of electric savings by the end of 2015/16.

The program is designed to encourage and support energy efficient retrofits in Manitoba Hydro facilities, when cost-effective to do so. The IRP provides technical support and financial assistance in the design and implementation of various energy efficient measures such as lighting, building envelope, HVAC systems, and custom measures. The program also ensures that newly constructed Manitoba Hydro facilities satisfy Manitoba Green Building Policy requirements.

The program's target market is composed of all Manitoba Hydro facilities, such as generating stations, commercial buildings, and corporate housing, where the opportunity for energy efficient retrofits exists. The program aims to have 100% of all Manitoba Hydro facilities satisfy Power Smart requirements.

	1992/93 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	1,345	23	**1,368**
Capacity Savings (MW)	14.1	0.2	**14.2**
Energy Savings (GW.h)	66.4	0.8	**67.2**
Utility Investment (Millions, 2015$)	$25.9	$0.7	**$26.6**

*Includes estimates for 2014/15

Power Smart Shops Program

The Power Smart Shops Program is scheduled to launch in the 2015/16 fiscal year and to run until 2020/21. In 2015/16, program participation is expected to be 500 projects, resulting in 0.6 GW.h and 0.1 MW of electric savings. Combined with achievements to date, participation will be 1,208 projects resulting in 1.3 GW.h and 0.3 MW of electric savings by the end of 2015/16.

The program is designed to promote energy efficiency to the hard-to-reach small commercial market such as restaurants, convenience stores, small offices, dental offices, salons, and flower shops. To be eligible, the business must be 10,000 square feet or less in size and a Manitoba Hydro commercial customer with either an electric or natural gas heating system. National chains and new construction projects are not eligible to participate.

The Power Smart Shops Program will utilize a full-service contractor delivery model and consist of a two-part offering: Firstly, the direct-installation of various free measures such as bathroom and kitchen faucet aerators, low-flow pre-rinse spray valves, and basic lighting measures. Secondly, a free lighting assessment and written report to identify energy-saving opportunities by retrofitting inefficient lighting. The program will cover up to 70% of the cost of qualifying lighting retrofits.

The small commercial market is a proven late adopter of energy efficient technologies due to a number of unique barriers that have not been specifically addressed by existing Power Smart for Business programs. Limited resources, costs of upgrades, and lack of industry exposure are all barriers that the Power Smart Shops Program aims to help overcome. The Program's aggressive incentives and the option to participate in the Power Smart PAYS Financing Program are anticipated to mitigate the upfront capital cost barrier faced by this market.

	2009/10 to 2014/15*	2015/16	Total to 2015/16
No. of Projects (annual)	708	500	**1,208**
Capacity Savings (MW)	0.2	0.1	**0.3**
Energy Savings (GW.h)	0.8	0.6	**1.3**
Natural Gas Savings (million m^3)	0.0	0.0	**0.0**
Utility Investment (Millions, 2015$)	$0.8	$0.3	**$1.1**
Customer Investment (Millions, 2015$)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2015$)	$0.8	$0.3	**$1.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $9			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $3			

The following convenient financing program offered by Manitoba Hydro supports energy efficiency upgrades by allowing customers to finance initial project costs and pay these costs back on their monthly Manitoba Hydro bill.

Power Smart for Business PAYS Financing

The Power Smart for Business PAYS (Pay As You Save) Financing Program was launched in September 2013. In 2015/16, the program is expected to finance 27 electrical projects and 6 natural gas projects. Combined with achievements to date, 44 electrical technologies and 12 natural gas technologies will be financed. The program is forecast to reach 0.2% of targeted electrical and natural gas customers by the end of 2015/16.

The program's objective is to assist commercial customers in reducing their energy and water consumption by offering extended financing terms for energy efficiency upgrades such as lighting, high efficiency natural gas furnaces, condensing and near-condensing boilers, insulation, geothermal systems, CO_2 sensors, custom measures (commercial and industrial applications), and WaterSense® labeled toilets and urinals. This offering compliments and supports the various incentive-based programs by assisting customers in managing the installation cost of their upgrade.

To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing repayment, thereby resulting in an energy bill that is slightly less than the total bill prior to the retrofit. Financing will be available for extended terms with 20 to 25 year amortization periods dependent on the upgrade, with the interest rate being fixed for the first 5 years. These are projects that would not likely have occurred without the availability of this convenient and flexible financing offering.

Note: Savings are included under the appropriate incentive based program.

	2013/14 to 2014/15*	2015/16	Total to 2015/16
No. of Loans (annual)	23	33	**56**
Average Loan Amount: $27,294			

*Includes estimates for 2014/15

Industrial

Manitoba Hydro offers incentive-based programs to address opportunities within the industrial market. These programs take a customer-focused approach to identify and address operating and production challenges in a manner that not only improves overall energy efficiency, but enhances productivity and competitiveness for Manitoba industry.

Manitoba's industrial market can be characterized as consisting of a large variety of industries with a broad size demographic of customers within each classification. While some sectors are responsible for higher percentages of consumption than others, no one industry sector is dominant within the province. In Manitoba, each sector is typically dominated by less than six customers, with the remaining customers being smaller with more specialized operations or substantively lower outputs. This diversity presents some unique challenges as opportunities to capture substantive savings are tied directly to specific industry business cycles within each industry sector that dictate major events such as equipment change-outs, plant overhauls, facility expansions, and new plant construction. These cycles are periodic and can stretch across decades.

Manitoba Hydro's industrial Power Smart programs must have broad appeal in order to be relevant and responsive to the needs of a diverse population of industrial customers.

Performance Optimization Program

The Performance Optimization Program was launched in June 1993. In 2015/16, the program is expected to achieve 17.0 GW.h and 2.1 MW of electric savings. Combined with achievements to date, the program is expected to achieve 552.6 GW.h and 104.4 MW by the end of 2015/16.

The program is designed to promote energy efficiency through the optimization of electric motor-driven industrial systems such as air compressors, pumps, fans and blowers, optimization of industrial refrigeration, process heating, electro-chemical processes systems, and implementation of plant-wide energy management systems. The program provides industrial and large commercial customers with technical support and financial incentives to assist in the identification, investigation, and implementation of system efficiency improvements throughout a facility.

The target market consists of approximately 2 000 industrial customers, with the program being available to both existing facilities and new construction projects. Emphasis is placed on the 300 largest customers who represent about 1/3 of the energy consumed in Manitoba. The average duration of a project from identification of the opportunity to implementation ranges from 6 months to 2 years, averaging approximately 18 months.

The actual number of project applications facilitated in any fiscal year and the savings achieved per project can vary dramatically based on project size, equipment age, and remaining life of the individual systems being optimized. However, savings levels are relatively consistent, thereby reflecting the capability within Manitoba Hydro's programs to adapt to available opportunities. Targeted companies may have multiple eligible energy conservation projects that are captured in a short period of time, resulting in intense periods of activity in a company or industry sector followed by a lull in activity thereafter as investment is recouped and productivity gains are utilized.

	1993/94 to 2014/15*	2015/16	Total to 2015/16
Capacity Savings (MW)	102.3	2.1	**104.4**
Energy Savings (GW.h)	535.6	17.0	**552.6**
Utility Investment (Millions, 2015$)	$42.3	$5.2	**$47.5**
Customer Investment (Millions, 2015$)	$93.7	$0.7	**$94.3**
Total DSM Investment (Millions, 2015$)	$136.0	$5.9	**$141.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $7,583			

*Includes estimates for 2014/15

Natural Gas Optimization Program

The Power Smart Natural Gas Optimization Program (NGOP) was launched in September 2006 and is scheduled to run until 2027/28. In 2015/16, the program is expected to achieve 1.0 million cubic metres in natural gas savings. Combined with achievements to date, the program is expected to achieve 16.0 million cubic metres in natural gas savings by the end of 2015/16.

The program's primary objective is to support the systematic improvement of natural gas equipment and processes for industrial and large institutional customers. The program supports customers by offering financial incentives for steam trap audits, feasibility studies and for energy efficient project implementation. The program was principally developed to promote custom applications within large industrial, institutional and commercial facilities comprised of roughly 1,400 customers in Manitoba. Since the launch of the program, it has become apparent that the small to medium industrial customers are also interested in pursuing energy efficiency with support from Manitoba Hydro. The scope of the NGOP has since been expanded to allow the program to respond to all industrial customer inquiries, regardless of the size of the facility or volume of natural gas consumed.

Like the Performance Optimization Program, the NGOP is a custom program that supports a variety of technologies across a wide variety of applications, including; boiler conversions, process water and air heat recovery, process equipment and pipe insulation, boiler economizers, and other available technologies. The program is designed to address key market barriers related to project costs, available benefits, cost/benefit ratios and desired return on investment. Current low natural gas commodity prices are challenging Manitoba Hydro customers' desired rates of return on investment in conservation initiatives.

	2006/07 to 2014/15*	2015/16	Total to 2015/16
Natural Gas Savings (million m^3)	15.0	1.0	**16.0**
Utility Investment (Millions, 2015$)	$4.9	$0.5	**$5.4**
Customer Investment (Millions, 2015$)	$28.3	$2.1	**$30.4**
Total DSM Investment (Millions, 2015$)	$33.2	$2.6	**$35.8**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $19,157			

*Includes estimates for 2014/15

Load Displacement & Alternative Energy

Bioenergy Optimization Program

The Bioenergy Optimization Program was launched in 2008 and is scheduled to run until 2017/18. In 2015/16, the program is expected to achieve 3.8 GW.h and 0.6 MW of electric savings. Combined with achievements to date, the program is expected to achieve in 61.8 GW.h and 7.2 MW of electric by the end of 2015/16.

The program is designed to encourage customers to install, operate, and maintain customer-sited load displacement generation systems that employ combined heat and power (CHP) and renewable fuels, specifically biomass. The target market consists of customers that have readily available, low-cost sources of biomass, a continual need for heat and power, and the capability to operate and maintain biomass-to-energy conversion systems. A series of biomass-to-energy demonstration projects were undertaken since the inception of the program in order to better assess the various pathways for converting biomass to useful energy. The knowledge gained has helped to focus the program, and identify the most promising technologies to pursue. Manitoba Hydro's program further supports customers in developing a thorough understanding of the costs and benefits of bioenergy systems, assisting with the development of strong business cases for future installations.

The remaining major customer sector targeted by the program is the manufacturing and processing sector. The size of systems anticipated is less than one MW electrical output. While initial projections for customer participation are relatively modest, opportunities for larger savings exist for the new Load Displacement Program which was launched in 2014. Government policy on renewable energy is anticipated to be a factor in the future uptake of renewable energy in Manitoba.

	2008/09 to 2014/15*	2015/16	Total to 2015/16
Capacity Savings (MW)	6.7	0.6	**7.2**
Energy Savings (GW.h)	58.0	3.8	**61.8**
Utility Investment (Millions, 2015$)	$12.7	$0.8	**$13.5**
Customer Investment (Millions, 2015$)	$27.3	$2.0	**$29.3**
Total DSM Investment (Millions, 2015$)	$40.0	$2.8	**$42.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $190,837			

*Includes estimates for 2014/15

Customer-Sited Load Displacement

The Load Displacement Program was launched in 2014. In 2015/16, the program is expected to achieve 57.2 GW.h and 8.0 MW of electric savings.

The program encourages customers to install, operate, and maintain customer-sited load displacement generation systems that employ combined heat and power (CHP) and rely on the use of waste streams and by-products, locally available, low cost sources of biomass fuel, and other renewable energy sources. The target market consists of several large-sized customers or customer sectors that are striving to optimize their operations and improve environmental performance.

Waste streams and by-products from manufacturing operations typically present a cost of disposal and an environmental liability to the manufacturer. Being able to convert waste streams and by-products into useful energy for the manufacturing operation is potentially a more sustainable practice and a means to reduce energy and disposal costs. Similarly, locally available low cost sources of biomass such as waste wood and crop residues can be harnessed as a sustainable and economic fuel source for on-site heat and power generation applications. Other emerging energy sources such as wind and solar may have potential in certain instances to offset purchased energy. Manitoba Hydro's Load Displacement Program offers technical and financial support to understand the feasibility to use these types of fuel sources, to implement the equipment and systems for load displacement generation, and to ensure ongoing, reliable operation of the energy production equipment.

Major customer sectors targeted by the program include forestry, chemicals, metals, oil and gas, and wastewater treatment. The size of these systems is anticipated to range from 1 MW to 15 MW of electrical load displacement via on-site generation. Installations are anticipated to cost between $3,500 to $5,000 per kW electric installed. Customer costs will be dependent upon existing infrastructure and operational capability.

	2014/15*	2015/16	Total to 2015/16
Capacity Savings (MW)	0.0	8.0	**8.0**
Energy Savings (GW.h)	0.0	57.2	**57.2**
Utility Investment (Millions, 2015$)	$0.8	$5.5	**$6.3**
Customer Investment (Millions, 2015$)	$1.6	$1.6	**$3.1**
Total DSM Investment (Millions, 2015$)	$2.4	$7.1	**$9.4**
Estimated Average Annual Bill Reduction per Customer (Electric): Variable depending on project size			

*Includes estimates for 2014/15

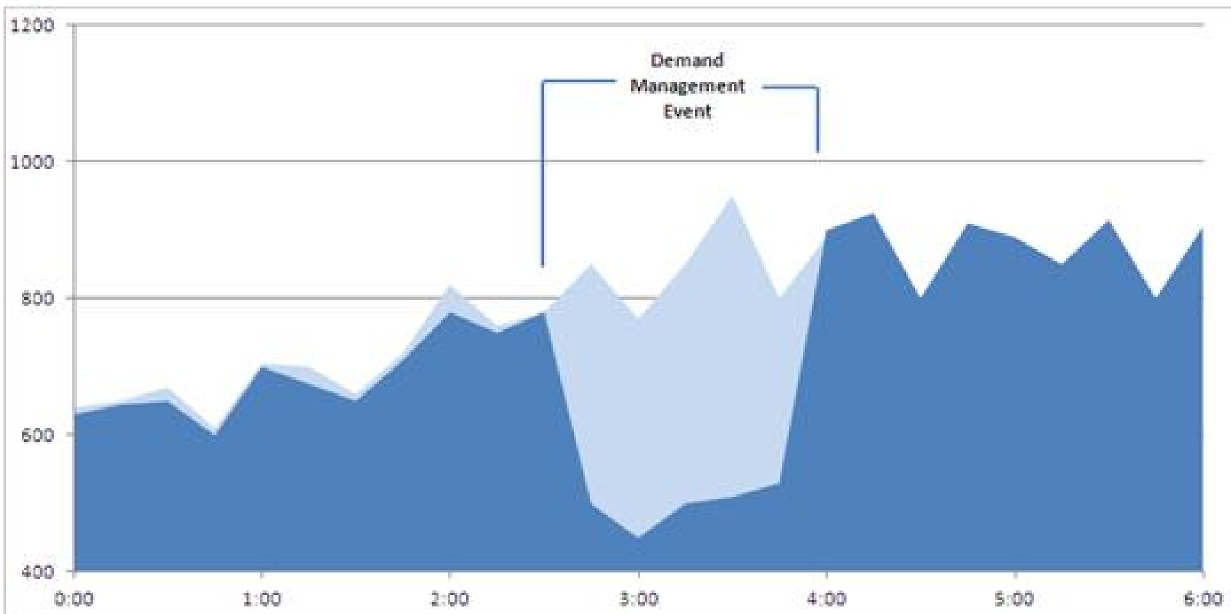
Load Management

Curtailable Rate Program

Under the Curtailable Rate Program, qualifying customers receive a monthly credit on load (kW) which can be curtailed on notice from Manitoba Hydro. To be eligible, customers' load/processes must be configured to allow them to meet the requested curtailment within the notification period as outlined under their chosen contract option.

	1990/00 to 2014/15*	2015/16	Total to 2015/16
No. of Customers (annual)	52	3	**55**
Capacity Savings (MW)	157.8	157.8	**157.8**
Utility Investment (Millions, 2015$)	$101.9	$6.0	**$107.9**

*Includes estimates for 2014/15



Section:	Tab 8: Appendix 8.1	**Page No.:**	14
Topic:	Demand Side Management		
Subtopic:	Industrial Programs		
Issue:	TOU Rates and Conservation Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Why are "conservation rates" planned for Residential and Commercial customers but not for Industrial customers?

RATIONALE FOR QUESTION:

There are no new conservation rates for industrial customers planned for the period 2014/15 to 2028/29

RESPONSE:

Manitoba Hydro is proposing a Time-of-Use ("TOU") rate design for the GSL > 30 kV customer classes because this rate design provides a more appropriate price signal for large energy consumers, than the current single block rate design. The TOU rate design provides specific price signals that are differentiated by the time of day (on-peak hours and off-peak hours) and the season in which that energy is consumed.

The higher on-peak values for energy reflect the higher demand for energy during these periods and the role that on-peak customer demand plays in the need for generation and transmission resources. It is anticipated that the higher winter season and on-peak rates will encourage customers to more actively manage energy consumption during these higher demand periods, as the rate will provide a stronger price signal than the present single block rate provides.

The differentiation in price between on-peak and off-peak consumption will provide an economic incentive to customers to shift their energy usage away from the on-peak time period. Customers that are able to accomplish this type of load shift might not reduce their overall quantity of energy consumed, but they will consume energy in a more economically efficient manner for themselves and for Manitoba Hydro.

Some customers may not be able to shift portions of their load away from the on-peak period. In those circumstances, the higher on-peak price may provide more economic incentive to find means to reduce their energy consumption in the on-peak period.

Manitoba Hydro's Industrial Power Smart Programs will support customer efforts to manage their on-peak consumption with comprehensive technical and financial support. The anticipated conservations savings from those efforts are captured in the DSM targets identified for Manitoba Hydro's industrial demand-side management programs.

Section:	Tab 8: Appendix 8.1	Page No.:	14
Topic:	Demand Side Management		
Subtopic:	Industrial Programs		
Issue:	TOU Rates and Conservation Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

The TOU rates proposed for large industrial customers are not referenced in the Power Smart Plan. Why are such rates not considered to be part of the Power Smart activities when future Conservation Rates for Residential and Commercial are?

RATIONALE FOR QUESTION:

There are no new conservation rates for industrial customers planned for the period 2014/15 to 2028/29

RESPONSE:

Please see the response to COALITION/MH-I-70 a.

Section:	Tab 9	Page No.:	11, 12 & 14
Topic:	Energy Supply		
Subtopic:	Exports		
Issue:	Historic Volumes and Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule similar to Figure 9.8 but which sets out on-peak Dependable and Opportunity sales (i.e., volumes, revenue and average price).

RATIONALE FOR QUESTION:

Manitoba Hydro states (page 11, lines 21-23) that as most dependable sales are for on-peak energy a price comparison with on-peak opportunity sales is appropriate.

RESPONSE:

Please see the table below.

TOTAL ON-PEAK SALES						
	DEPENDABLE ON-PEAK SALES			**OPPORTUNITY ON-PEAK SALES**		
	GWh	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**
2005/06	3,742	228	60.62	3,142	245	72.73
2006/07	3,510	211	59.69	1,972	135	66.26
2007/08	3,612	198	54.56	2,212	162	66.19
2008/09	3,702	221	59.4	1,802	153	71.78
2009/10	3,073	180	58.15	2,497	84	31.14
2010/11	3,051	164	53.58	2,268	76	31.90
2011/12	3,240	164	50.38	1,952	59	28.76
2012/13	3,178	166	51.87	2,165	69	29.87
2013/14	2,930	168	56.82	2,492	82	36.95
2014/15	2,181	131	59.39	1,789	67	33.33

Data for 2014/15 is up to Dec 31, 2014

NOTE: Data prior to 2005/06 is not available in the On/Off peak format

Section:	Tab 10 Tab 11: Appendix 11.1 Tab 11: Appendix 11.43	**Page No.:**	6 Various Letters 2
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 143/13		
Issue:	DSM Deferral Account - Proposed Disposition		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the actual level of electric DSM spending in 2012/13 was $26.6 M (per Manitoba Hydro's letter of March 25, 2014). If not what was the amount?

RATIONALE FOR QUESTION:

To confirm DSM Deferral Account balance as of March 31, 2014 and to clarify the proposed disposition of the balance.

RESPONSE:

Manitoba Hydro confirms that electric DSM spending was $26.6 million for fiscal 2012/13.

Section:	Tab 10 Tab 11: Appendix 11.1 Tab 11: Appendix 11.43	**Page No.:**	6 Various Letters 2
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 143/13		
Issue:	DSM Deferral Account - Proposed Disposition		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the actual level of electric DSM spending for 2013/14.

RATIONALE FOR QUESTION:

To confirm DSM Deferral Account balance as of March 31, 2014 and to clarify the proposed disposition of the balance.

RESPONSE:

Electric DSM spending for fiscal 2013/14 was $26.1 million.

Section:	Tab 10 Tab 11: Appendix 11.1 Tab 11: Appendix 11.43	**Page No.:**	6 Various Letters 2
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 143/13		
Issue:	DSM Deferral Account - Proposed Disposition		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please set out the calculation of the $16.3 M included in the DSM Deferral Account as of March 31, 2014 (per Appendix 11.43).

RATIONALE FOR QUESTION:

To confirm DSM Deferral Account balance as of March 31, 2014 and to clarify the proposed disposition of the balance.

RESPONSE:

The following table provides the calculation of the $16.3 million included in the Electric DSM deferral account at March 31, 2014.

($ millions)	2013	2014	Total
DSM spending identified in Board Order 43/13	$ 34.0	$ 35.0	$ 69.0
Actual DSM spending	26.6	26.1	52.7
DSM Deferral - electric	$ 7.4	$ 8.9	$ 16.3

Section:	Tab 10 Tab 11: Appendix 11.1 Tab 11: Appendix 11.43	**Page No.:**	6 Various Letters 2
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 143/13		
Issue:	DSM Deferral Account - Proposed Disposition		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please clarify how Manitoba Hydro has treated this balance for purposes of determining the revenue requirement for 2014/15 and 2015/16 as set out in the current Application. In particular, with respect to Appendix 11.43, does the $16.3 M in the DSM deferral account affect in any way the forecast DSM amortization for 2014/15 through 2016/17?

RATIONALE FOR QUESTION:

To confirm DSM Deferral Account balance as of March 31, 2014 and to clarify the proposed disposition of the balance.

RESPONSE:

The DSM deferral balances were established as of March 31, 2014. These balances have not been amortized and as such are not included in revenue requirement for 2014/15, 2015/16 or 2016/17.

Section:	Tab 10	**Page No.:**	10
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 150/08		
Issue:	Independent Benchmarking Study – Status		

PREAMBLE TO IR (IF ANY):

The status of the directive regarding an Independent Benchmarking Study is noted as "deferred". However, the subsequent discussion does not indicate when the study will be done in the future but, rather, suggests that Manitoba Hydro does not see any value in carrying out such a study.

QUESTION:

Please clarify whether Manitoba Hydro intends to carry out an Independent Benchmarking Study as directed by the PUB and, if so, when.

RATIONALE FOR QUESTION:

To clarify Manitoba Hydro's plans regarding the PUB's Independent Benchmarking Study Directive

RESPONSE:

Manitoba Hydro intends to further assess the value of carrying out an independent benchmarking study subsequent to the implementation of IFRS. When Manitoba Hydro has completed this assessment, it will seek further direction from the PUB.

Section:	Tab 10	**Page No.:**	10
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 150/08		
Issue:	Independent Benchmarking Study – Status		

PREAMBLE TO IR (IF ANY):

The status of the directive regarding an Independent Benchmarking Study is noted as "deferred". However, the subsequent discussion does not indicate when the study will be done in the future but, rather, suggests that Manitoba Hydro does not see any value in carrying out such a study.

QUESTION:

If Manitoba Hydro does not intend to carry out the study, why hasn't Manitoba Hydro included, as part of this Application, a request for the PUB to review/vary its Orders (both 150/08 and 5/12) as they apply to the Independent Benchmarking Study?

RATIONALE FOR QUESTION:

To clarify Manitoba Hydro's plans regarding the PUB's Independent Benchmarking Study Directive

RESPONSE:

Please see the response to COALITION/MH-I-73a.

Section:	Tab 10 PUB Order 159/04	Page No.:	7 (ii)
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement - General		

PREAMBLE TO IR (IF ANY):

PUB Order 159/04 (page (ii)) sets out the terms of the 2004 Settlement Agreement as summarized by Manitoba Hydro to be:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

2. INAC would pay $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;

3. INAC, on behalf of the Federal government, would pay MH 69% of the $28.8 million of MH's diesel-related undepreciated capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and no later than January 7, 2006;

4. MH would request that other federal and provincial government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's $28.8 million of undepreciated capital cost;

5. MH would assume the remaining 21% of undepreciated capital costs on behalf of Residential and General Service customers that are neither First Nations members nor government accounts; and

6. For major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nation communities, and secure funding prior to making further capital expenditures.

QUESTION:

Are there any other terms/provisions in the Settlement Agreement that affect Manitoba Hydro's outstanding liabilities or costs associated with the Diesel Communities?

RATIONALE FOR QUESTION:

To clarify if there are any other terms in the Settlement Agreement that are relevant to Manitoba Hydro's rate setting.

RESPONSE:

Consistent with the PUB's ruling in Order 33/15 regarding COALITION/MH-I-75a)-b), 76 a)-c), 77a)-c), 78 a)-c), 79 a)-c), and 80 a)-b), the PUB has determined that the issues related to rates in the remaining four Manitoba diesel communities should be examined after the Settlement Agreement has been filed, and ordered that it would not require Manitoba Hydro to respond to these IRs at this time.

Section:	Tab 10 PUB Order 159/04	Page No.:	7 (ii)
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement - General		

PREAMBLE TO IR (IF ANY):

PUB Order 159/04 (page (ii)) sets out the terms of the 2004 Settlement Agreement as summarized by Manitoba Hydro to be:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

2. INAC would pay $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;

3. INAC, on behalf of the Federal government, would pay MH 69% of the $28.8 million of MH's diesel-related undepreciated capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and no later than January 7, 2006;

4. MH would request that other federal and provincial government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's $28.8 million of undepreciated capital cost;

5. MH would assume the remaining 21% of undepreciated capital costs on behalf of Residential and General Service customers that are neither First Nations members nor government accounts; and

6. For major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nation communities, and secure funding prior to making further capital expenditures.

QUESTION:

If so, please outline what they are and their current status.

RATIONALE FOR QUESTION:

To clarify if there are any other terms in the Settlement Agreement that are relevant to Manitoba Hydro's rate setting.

RESPONSE:

Consistent with the PUB's ruling in Order 33/15 regarding COALITION/MH-I-75a)-b), 76 a)-c), 77a)-c), 78 a)-c), 79 a)-c), and 80 a)-b), the PUB has determined that the issues related to rates in the remaining four Manitoba diesel communities should be examined after the Settlement Agreement has been filed, and ordered that it would not require Manitoba Hydro to respond to these IRs at this time.

Section:	Order 159/04 Tab 10 2012/13 & 2013/14 GRA, Tab 13: Appendix 13.1	Page No.:	(ii) & 6 7 14
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Retirement of Accumulated 2004 Deficit		

PREAMBLE TO IR (IF ANY):

Order 159/04 indicated that, under the Settlement Agreement, Manitoba Hydro "would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement."

Appendix 13.1 (from the previous GRA) notes that an allocation of export revenues to Diesel is currently being applied against the accumulated deficit which is expected to fully paid off by March 31, 2014.

QUESTION:

Please provide a 2004-2014 continuity schedule for the accumulated deficit that sets out the initial accumulated deficit (as of 2004), the amount retired each year (through the allocation of net export revenues) and the outstanding balance (if any) as of March 31, 2014.

RATIONALE FOR QUESTION:

The Settlement Agreement expected that the accumulated Diesel deficit as of March 31, 2014 would be retired by March 31, 2014 through an allocation of net export revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Order 159/04 Tab 10 2012/13 & 2013/14 GRA, Tab 13: Appendix 13.1	**Page No.:**	(ii) & 6 7 14
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Retirement of Accumulated 2004 Deficit		

PREAMBLE TO IR (IF ANY):

Order 159/04 indicated that, under the Settlement Agreement, Manitoba Hydro "would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement."

Appendix 13.1 (from the previous GRA) notes that an allocation of export revenues to Diesel is currently being applied against the accumulated deficit which is expected to fully paid off by March 31, 2014.

QUESTION:

What has been the impact on Manitoba Hydro's retained earnings (as of March 2014) of allocating a portion of export revenues to "retire" the accumulated deficit as opposed to recovering the deficit through Diesel rates as was the prior practice?

RATIONALE FOR QUESTION:

The Settlement Agreement expected that the accumulated Diesel deficit as of March 31, 2014 would be retired by March 31, 2014 through an allocation of net export revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	Page No.:	7 (ii) & 6
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Allocation of Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Order 159/04 indicated that, under the Settlement Agreement, Manitoba Hydro "would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement."

QUESTION:

Please confirm that this item is still outstanding. If not, please indicate where the PUB has provided its approval.

RATIONALE FOR QUESTION:

To confirm the status of the Settlement Agreement provision whereby Manitoba Hydro would request Board approval for an allocation of net electricity export revenues: i) first to retire the diesel zone accumulated deficit and, then once the deficit had been recovered and, then, ii) to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	Page No.:	7 (ii) & 6
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Allocation of Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Order 159/04 indicated that, under the Settlement Agreement, Manitoba Hydro "would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement."

QUESTION:

When does Manitoba Hydro plan to request this approval? Will it be part of the forthcoming Cost of Service Study Application?

RATIONALE FOR QUESTION:

To confirm the status of the Settlement Agreement provision whereby Manitoba Hydro would request Board approval for an allocation of net electricity export revenues: i) first to retire the diesel zone accumulated deficit and, then once the deficit had been recovered and, then, ii) to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	**Page No.:**	7 (ii) & 6
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Allocation of Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Order 159/04 indicated that, under the Settlement Agreement, Manitoba Hydro "would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement."

QUESTION:

Why is Manitoba Hydro requesting final approval of the interim Diesel Rates that incorporate this term of the Agreement if PUB approval for the change in COSS treatment of export revenues has not been granted?

RATIONALE FOR QUESTION:

To confirm the status of the Settlement Agreement provision whereby Manitoba Hydro would request Board approval for an allocation of net electricity export revenues: i) first to retire the diesel zone accumulated deficit and, then once the deficit had been recovered and, then, ii) to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	Page No.:	7 (ii) & 7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – INAC and Other Governments' Pre-2004 Obligations		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that INAC (now AANDC) has paid $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004 as required under the Settlement Agreement. If not, what is the status of this item?

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the accumulated 2004 deficit and undepreciated capital as of 2004.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	Page No.:	7 (ii) & 7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – INAC and Other Governments' Pre-2004 Obligations		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that INAC (now AANDC), on behalf of the Federal government, paid MH 69% of the $28.8 million of MH's diesel-related undepreciated capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and no later than January 7, 2006. If so, please indicate whether interest was paid on any amounts paid between July 7, 2005 and July 7, 2006. If not, what is the status of this item?

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the accumulated 2004 deficit and undepreciated capital as of 2004.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04	**Page No.:**	7 (ii) & 7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – INAC and Other Governments' Pre-2004 Obligations		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that Manitoba Hydro has requested and received from other federal and provincial government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba) 10% of the undepreciated capital balance as of March 31, 2004. If not, what is the status of this item?

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the accumulated 2004 deficit and undepreciated capital as of 2004.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04 2012/13 & 2013/14 GRA, Appendix 11.1	Page No.:	7 (ii) 3
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post-2004 Capital Contributions		

PREAMBLE TO IR (IF ANY):

Appendix 11.1 (page 3) from the 2012/13 & 2013/14 GRA indicated that the Agreement contemplated the funding of capital costs through customer contributions rather than rates.

QUESTION:

Please provide a schedule that sets out, by community and by capital project, the capital spending in each year since 2004 and forecast through to 2016/17.

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the provision of capital contributions to fund post-2004 capital expenditures.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04 2012/13 & 2013/14 GRA, Appendix 11.1	Page No.:	7 (ii) 3
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post-2004 Capital Contributions		

PREAMBLE TO IR (IF ANY):

Appendix 11.1 (page 3) from the 2012/13 & 2013/14 GRA indicated that the Agreement contemplated the funding of capital costs through customer contributions rather than rates.

QUESTION:

Please provide a schedule that for each capital project noted in response to part (a) sets out the capital contribution to be made by i) AANDC, ii) Other Federal/Provincial Government Customers and iii) Manitoba Hydro in accordance with the Settlement Agreement. In the same schedule please indicate, for spending up to March 31, 2014, whether these contributions have been received.

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the provision of capital contributions to fund post-2004 capital expenditures.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 Order 159/04 2012/13 & 2013/14 GRA, Appendix 11.1	Page No.:	7 (ii) 3
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post-2004 Capital Contributions		

PREAMBLE TO IR (IF ANY):

Appendix 11.1 (page 3) from the 2012/13 & 2013/14 GRA indicated that the Agreement contemplated the funding of capital costs through customer contributions rather than rates.

QUESTION:

In those cases where contributions have not been received as per the Agreement please indicate the status.

RATIONALE FOR QUESTION:

To confirm whether INAC (now AANDC) and other government customers have met their obligations under the provisions of the Settlement Agreement regarding the provision of capital contributions to fund post-2004 capital expenditures.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	10 Order 1/10 2010 Diesel Application, PUB/MH 9 c)	Page No.:	7 9 & 10
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post Settlement Agreement Financial Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the actual operating statement for the Diesel Communities for the each of the years for the years from 2004/2005 to 2013/2014. Please do not include notional interest, depreciation and capital taxes that do not accrue as a result of capital contributions.

RATIONALE FOR QUESTION:

To confirm whether, based on the Settlement Agreement, the Manitoba Hydro's operation of the Diesel Communities is now on a financially sound basis.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	10 Order 1/10 2010 Diesel Application, PUB/MH 9 c)	Page No.:	7 9 & 10
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post Settlement Agreement Financial Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update or correct the table on Page 9 of Order 1/10 where required.

RATIONALE FOR QUESTION:

To confirm whether, based on the Settlement Agreement, the Manitoba Hydro's operation of the Diesel Communities is now on a financially sound basis.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	10 Order 1/10 2010 Diesel Application, PUB/MH 9 c)	Page No.:	7 9 & 10
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Post Settlement Agreement Financial Results		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the table provided in response to PUB/MH 9 c) from the 2010 Diesel Application proceeding to include actuals up to March 31, 2014.

RATIONALE FOR QUESTION:

To confirm whether, based on the Settlement Agreement, the Manitoba Hydro's operation of the Diesel Communities is now on a financially sound basis.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 2012/13 & 2013/14 GRA, CAC/MH I-8 a)	**Page No.:**	7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Recent DCOSS		

PREAMBLE TO IR (IF ANY):

The response to CAC/MH I-8 a) indicated that a DCOSS based on the 2013/14 forecast year would be developed and incorporate actual results for the years 2011/12 and 2012/13.

QUESTION:

Please provide a copy the referenced DCOSS for the 2013/14 forecast year.

RATIONALE FOR QUESTION:

To understand the recent financial performance of Manitoba Hydro's operation of the Diesel Communities.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 10 2012/13 & 2013/14 GRA, CAC/MH I-8 a)	**Page No.:**	7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Directives from Order 134/10		
Issue:	Diesel Settlement Agreement – Recent DCOSS		

PREAMBLE TO IR (IF ANY):

The response to CAC/MH I-8 a) indicated that a DCOSS based on the 2013/14 forecast year would be developed and incorporate actual results for the years 2011/12 and 2012/13.

QUESTION:

If a more recent DCOSS has been completed please provide a copy.

RATIONALE FOR QUESTION:

To understand the recent financial performance of Manitoba Hydro's operation of the Diesel Communities.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 4	**Page No.:**	pp. 2&3 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Project Justification (CPJ)		
Issue:	Understand CPJ and prioritization process		

PREAMBLE TO IR (IF ANY):

A Capital Project Justification is initiated when a capital project is identified as it is stated on page 2 of 26 tab 4. The CPJ contains information that identify the needs for the project. Furthermore; CPJs are examined to confirm the need based on a number of criteria. In addition, Manitoba Hydro assesses the proposed projects and whether projects of lesser priority can be displaced.

QUESTION:

Please provide supporting CPJ documentation justifying all new projects included in the CEF 2014.

RATIONALE FOR QUESTION:

Confirm the prudence and reasonableness of the new projects included in the CEF 2014 and test whether cost effective prioritization is taking place. Does not duplicate PUB/Hydro 1-17 – 1-26.

RESPONSE:

The following twenty-two new CPJs included in CEF14 are attached.

	Project	Total Project Cost
Attachment 1	Adelaide Station	$ 62.106
Attachment 2	Grand Rapids Hatchery Upgrade and Expansion	$ 23.509
Attachment 3	York Stn Banks 1,3,5 & Switchgear Addition	$ 18.481
Attachment 4	Southern AC System Breaker Replacements	$ 14.693
Attachment 5	Jenpeg Unit 1 Fire Rehabilitation	$ 14.000
Attachment 6	Souris East Transformer Capacity Enhancement	$ 11.302
Attachment 7	Jenpeg U4 Partial Mechanical Overhaul	$ 11.233
Attachment 8	Gen South Roof Replacement Program	$ 6.339
Attachment 9	Kettle GS Petroleum Storage Facility	$ 5.043
Attachment 10	Brandon Victoria Stn 115kV Circuit Breaker Repl.	$ 4.226
Attachment 11	Bipole I&II Failed Anchor Replacement	$ 3.500
Attachment 12	Anola DSC RM of Springfield	$ 4.000
Attachment 13	Winkler West DSC	$ 4.550
Attachment 14	Norway House Bank Addition	$ 4.000
Attachment 15	Ste. Agathe Stn Bank Addition	$ 2.100
Attachment 16	Hochfeld DSC	$ 5.000
Attachment 17	Brandon West 4kV - 12kV Conversion	$ 4.650
Attachment 18	Glenboro Town 8kV to 25kV Conversion	$ 2.000
Attachment 19	Relocate L17 to Semple Stn. Underground	$ 2.300
Attachment 20	Winnipeg Area 66 kV Line Upgrades	$ 2.031
Attachment 21	Neepawa 66 kV Improvements	$ 9.501
Attachment 22	Whiteshell Station Bank 1 Replacement	$ 3.027

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1485.02

DATE: 2014 05 20
Financial Planning

CAPITAL PROJECT JUST
FOR

Adelaide Station

REVIEWED BY:
(Owning Dept Manager)
Charles Steele, P.Eng. 2014 03 28

NOTED BY:
(if applicable)

Coordinating Division: 2014-03-24

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 03 28

Business Unit V.P.: 2014-04-14

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- [x] Safety
- [ ] System Supply
- [x] System Reliability
- [ ] Customer Service
- [ ] Efficiency
- [ ] Environmental

NERC COMPLIANCE: ☐ **YES** ☐ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

BUDGET $: (Total Net Cost)	$62,106,000
START DATE: (1st Cost Flow)	2013 09
IN-SERVICE DATE: (Last Major In-service Date)	Multi – 2020 03

OWNING DIVISION: G13800 / Distribution E&C Winnipeg

I.M. NODE NUMBER: 1.10.3.6.5.1

W.B.S. NUMBERs: P:23102

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Kristin Braid
K Braid, P.Eng. 2014 03 2

DATE PREPARED: 2014 03 06

REPORT NUMBER: 9357

FILE NUMBER (Optional):

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Adelaide Station

Recommendation
Construct new Adelaide Station with 3 x 66kV-12kV, 30 MVA transformers and three line-ups of switchgear for twenty-three feeder positions, transfer of existing King Station distribution and salvage of King Station for an estimated cost of $62.1M. The in-service date for Adelaide Station is 2017 03 31, the in-service date for the load transfer and salvage of King Station is 2020 03 31.

Project Scope

The scope of the project includes:

-Install a control building for 12kV switchgear, communications/control/protection equipment etc. on Manitoba Hydro-owned property on the north side of Notre Dame Ave. between Hargrave St. and Adelaide St.
- Install 66kV GIS building/equipment for station supply terminations.
- Installation of three 66kV - 12kV, 30 MVA, 65C rated transformers with load tap changers.
- Installation of three lineups of 2500A, Type 2B 12kV switchgear with an internal transfer bus for twenty-three feeder positions within the new control building.
- Protection/Metering equipment should be connected to new station automation system and communicate to SCC, with data to be made available on the Metering Web Application.
- Installation of bank cables from the transformers to the switchgear.
-Installation of 2 x 3km lengths of 66kV cable through new ductline to extend 66kV line W6 to terminate at the new station site.
- Installation of new distribution ductline egresses from the new station to connect to the existing ductline system in the downtown area.
- Reconnection of existing 12kV feeders to the new station.
-Installation of 12kV-4kV transformers at the King (1) Station site to re-supply the 4kV distribution from that station. These transformers will be supplied by new 12kV feeders from Adelaide Station.
-Salvage of the existing electrical equipment from King (1) Station.

Background

King (1) Station was built in the early 1900's to serve load in Downtown Winnipeg and now supplies approximately 1/3 of the distribution load in the downtown area. At 100 years old, the station building is in need of structural repair and there are numerous safety, operating and maintenance concerns with the electrical equipment in use. The identified concerns include a leaky roof, inadequate ventilation in the enclosed switchyard, and significant steel corrosion in the basement that extends under the sidewalk/roadway. Additionally, there is no fire extinguishing (i.e. transformer deluge) system, no blast walls separating equipment in the congested switchyard, transformers with failing parts, underrated switching equipment at all voltage levels, suspected inadequate station grounding, and asbestos materials in use.

King (1) Station currently peaks at approximately 80% of its firm rating in summer. As loading in the downtown area has grown, load transfers to neighbouring York (2) Station has allowed the King (1) Station

Background

loading levels to remain below the station firm rating. The expansion of York (2) Station planned for 2016 provides for future load growth, and it will have sufficient capacity to continue to support King (1) and other neighbouring stations by accepting load transfers from those stations as they reach their capacity. However, there is not enough installed capacity or expansion capability at other stations in the downtown area, York (2) included, to assume the entire load from King (1) Station. There are also concerns with aging equipment at those other neighbouring stations.

Alternatives to ensure continued available capacity and reliable supply to the downtown area of Winnipeg, and to address the aging infrastructure concerns and vital operating issues at King (1) Station, were investigated.

Justification

Constructing the new Adelaide Station will allow for the decommissioning of King (1) Station, addressing all concerns with safety and aging infrastructure at King (1) Station.

Replacing the aging King (1) Station building and equipment will ensure that reliability of supply in the downtown area is maintained. Although Adelaide will be constructed with only a minimal increase in total capacity at ISD, as a proposed 6-bank station, the future expansion capability of Adelaide Station supports longer term capacity and reliability improvement plans, including the requirement to decommission aging equipment at other stations in the downtown area, namely Edmonton (21) and Sherbrook (14) Stations.

While there is an existing project to increase capacity at York (2) Station in 2016. Relying on this plan alone to support load growth in the downtown area concentrates high-profile customers at one station, increasing the impact of outages. There will also be an increase risk of exposure to cable faults with longer cable runs to extend new feeders from York (2) Station all over the downtown area. Building Adelaide Station will result in a distribution system that is more reasonably dispersed.

Adelaide Station also provides sufficient area capacity to allow the proposed William Station project to be deferred. Five feeders from the new Adelaide Station will be expressed through new ductline towards the Health Science Centre (HSC) to aid Sherbrook (14) Station in supplying that area. Sherbrook (14) Station does not have capacity to continue to handle load growth around the HSC Complex by itself. Already, load transfers to Edmonton (21) have been necessary to keep Sherbrook (14) Station loading below its firm capacity.

The engineering, procurement and construction of the new Adelaide Station can be contracted outside of Manitoba Hydro. As such, the in-service date for the new station is March 2017, with the connection of the existing distribution circuits and salvage of the existing electrical equipment at King (1) Station planned to be completed by March 2020. Limited reliance on our already stressed internal resources, provides expectation estimated costs and schedule can be maintained.

Refurbishing King (1) Station at its current location, as proposed in Alternative Two, has an inherent high risk component which is likely to drive up project costs. The high risk component is due to the many unknowns concerning the integrity of the building superstructure and the feasibility of relying on a 100-year-old asset, the complexity of the project and the impact on internal resources. Proceeding with contracted resources on a new site, as proposed in the Recommended Option, will realize a new station at least three years in advance of the schedule projected in Alternative Two.

Justification

Capital Investment Categorization:

Driver	Category	Sub-Category	Split	Amount
Reliability (F3)	Aging Infrastructure (FA)	New Asset Addition (HN)	45%	$ 27,947,700
Safety (F4)	Employee Safety (FF)	New Asset Addition (HN)	35%	$ 21,737,100
Reliability (F3)	Op. Enhancement (FT)	New Asset Addition (HN)	10%	$ 6,210,600
Reliability (F7)	Cap. Enhancement (FD)	New Asset Addition (HN)	10%	$ 6,210,600
			Total:	$ 62,106,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.4%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Construct Adelaide Station to Replace King (1) Station This option involves building a distribution station on a new site equipped with three transformer banks and switchgear lineups to replace the existing King (1) Station.	($46,997,000)

Other Alternatives Considered	NPV Benefits/(Costs)
Alternavtive One: Refurbish King (1) Station This option involves refurbishing the existing King (1) Station at its current site, addressing all of the safety, aging infrastructure, operating and maintenance concerns at the station. Although the estimated costs to reconnect the 66kV supplies and distribution feeders to this station is less than the Recommended Option, the station cost is similar to building Adelaide Station, but is only based on what rehabilitation could be estimated by visual inspection. There is risk of cost escalation for the unknown building condition as well as the continued reliance on a 100-year old structure.	($34,776,000)

Risk Analysis

The contract to build this station will be put out for tender. There is risk that bids may be higher than estimated station costs.

Soil conditions at the newly-acquired property for the new station are unknown and may affect site preparation and stations design.

The project scope includes the installation of new ductline to extend 66kV supply to the station site. There

Risk Analysis

are many existing utilities under the streets in the downtown area, including existing and proposed new distribution ductline for the 12kV and 4kV circuits in the area, which may affect the alignment and/or preferred routing of the 66kV ductline.

Contingency has been added to estimated project costs for the Recommended Option to account for variations among the project bids, unknown soil conditions and 66kV ductline design.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2013/14	$ 50
2014/15	$ 728
2015/16	$ 21,185
2016/17	$ 22,895
2017/18	$ 8,803
2018/19	$ 5,024
2019/20	$ 3,421
Total	$ 62,106

Proposed Schedule

Issue an RFP for Consulting Design Services for a Perimeter Wall and Building – March 2014
Building and Wall Design complete – August 2014
Station RFP issue – September 2014
Station RFP close – December 2014
Award contract to build new station – May 2015
Building Construction Commences – June 2015
Transformer & Switchgear Arrival – May 2016
Complete Equipment Installation – January 2017
Commissioning New Station – February/March 2017
Load Transfer & Salvage of King (1) Station – March 2020

Related Projects

Reference Documents

Distribution Planning Study - DEW W14-01: Adelaide Station

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02
DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION FOR

Grand Rapids Hatchery Upgrade and Expansion

REVIEWED BY:
Angie Adams, New Generation Construction

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department: (if over $1 million) 2014/10/07

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/07

Business Unit V.P.: 7 Oct 2014

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☐ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☒ Environmental

NERC COMPLIANCE*: ☐ **YES** ☒ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$23,509,497
START DATE: (1st Cost Flow)	2013 05
IN-SERVICE DATE: (Last Major In-service Date)	2018 03
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION:

I.M. NODE NUMBER: 1.5.1.6.4

W.B.S. NUMBERs: P:21656

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: A.R. Adams

DATE PREPARED: 2014-10-07

REPORT NUMBER:

FILE NUMBER (Optional):

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Grand Rapids Hatchery Upgrade and Expansion

Recommendation

That an upgrade and expansion of the Grand Rapids Hatchery (GRH) be pursued to fulfill Lake Sturgeon stocking commitments under the Keeyask *Environment Act* licence as well as strategic commitments related to the impacts of existing facilities. The upgrade and expansion will increase capacity and reliability and provide the standard of water quality and level of biosecurity required to meet recently introduced national and provincial regulatory requirements.

Project Scope

The following is included in the scope of the project:

- Upgrade hatchery to modern production infrastructure and practices. The critical areas of review include water sources, water treatment, building infrastructure, fish rearing systems and effluent treatment
- Expand capacity of existing facility through tank replacement/reconfiguration and upgrade of supporting water treatment infrastructure
- Modifications to the Research Centre (a separate facility on the GRH site), including well and potable water supply, to serve as a temporary production facility during hatchery upgrade and expansion, and the purchase of portable satellite facilities to allow for fish rearing during hatchery construction
- Install electrical service from Grand Rapids Generating Station service to the hatchery
- Final design engineering (via external consultant)
- Internal Manitoba Hydro project management

Background

As a requirement of the Keeyask *Environment Act* licence, Manitoba Hydro must begin stocking lake sturgeon as early as 2015 when in-stream construction may disrupt spawning. Sturgeon stocking has been integrated with other fish compensation measures required by regulators for the Keeyask Project. Similar commitments under the Conawapa EIS, should the project be pursued in the future, are anticipated.

The strategic importance of mitigating unresolved impacts of existing facilities and operations has become increasingly important in recent years as demonstrated during licensing hearings for Wuskwatim, Bipole III and Keeyask, and culminating in the requirement for a Regional Cumulative Effects Assessment of Manitoba Hydro's existing facilities and operations. In addition, Manitoba Conservation and Water Stewardship has begun to consider social and environmental considerations in their Water Power Act processes such as the current Lake Winnipeg Regulation and Churchill River Diversion final licensing. In the case of LWR, the Clean Environment Commission will be conducting a public review including the environmental aspects. It is likely that upcoming processes, such as relicensing of Grand Rapids Generating Station in 2017, could trigger Environment Act reviews in which historical and ongoing impacts will be examined. Continued stocking of Lake Sturgeon produced at Grand Rapids Hatchery demonstrates that Manitoba Hydro is addressing impacts of existing facilities. It is therefore of strategic importance in ensuring continued licensing and operation of Manitoba Hydro's existing system with a minimum of new restrictions and infrastructure requirements.

To accommodate additional Lake Sturgeon stocking requirements for Keeyask and Conawapa, the Keeyask

Background

EIS had contemplated the construction of a new hatchery on the lower Nelson River. In January 2012, Manitoba Hydro underwent a competitive Request for Proposal (RFP) process to engage a consultant with expertise in fish hatchery design. The successful consulting firm, HDR Corporation, proceeded with a conceptual and preliminary design of a Lower Nelson River Hatchery (LNRH). Cost estimates received from the consultant of $40-$50 million were much higher than expected.

As a result, an option to upgrade and expand Manitoba Hydro's GRH was subsequently examined by HDR Corporation as a more economic alternative to constructing a LNRH. The Grand Rapids Fish Hatchery does not currently have the fish production capacity required to meet either Keeyask commitments or any future potential Conawapa commitments.

In addition, although fish husbandry and biosecurity practices at the GRH have been significantly improved since Manitoba Hydro began staffing the facility in fall of 2012, infrastructure modernization is required to provide the standard of water quality and level of biosecurity required to meet recently introduced national and provincial regulatory requirements, including aquatic animal health compartmentalization standards under the Canadian Food Inspection Agency.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The project supports the Corporate goal to "Protect the environment in everything that we do" as the fish hatchery represents a significant component of Manitoba Hydro's role in sturgeon stewardship and our commitment to Lake Sturgeon protection and enhancement. Lake Sturgeon is currently under federal review for listing as endangered under the *Species At Risk Act (SARA)*. A listing under the *SARA* would significantly impact Manitoba Hydro operations and future developments.

As a requirement of the Keeyask *Environment Act* licence, MH must begin stocking lake sturgeon in 2015 when in-stream construction may disrupt spawning. As some spawning habitat is expected to remain accessible and suitable during construction of Keeyask, the full stocking plan requirements do not come into effect until the station is in-service (November 2019) at which time the additional capacity provided by the GRH upgrade and expansion must be available.

Continued stocking of Lake Sturgeon to mitigate unresolved impacts of existing facilities and operations is of strategic importance in ensuring licensing and continued operation of Manitoba Hydro's existing system with a minimum of new restrictions and infrastructure requirements. This is relevant to 1) current and upcoming relicensing and final licensing processes such as Grand Rapids Generating Station, Lake Winnipeg Regulation and Churchill River Diversion; 2) other regulatory processes such as major maintenance and rehabilitation; and 3) regulatory/public reviews of existing facilities such as the Regional Cumulative Effects Assessment of existing facilities and operations.

In addition to increased capacity, the upgrade and expansion will increase the reliability of fish production for Keeyask and other Lake Sturgeon rearing conducted by MH as part of its integrated, multi-facetted approach to stewardship of the species. It will also improve employee safety and modernize obsolete and high maintenance assets so as to meet more stringent national and provincial regulatory requirements.

The risk of deferring the project is that MH will be unable to rear sufficient Lake Sturgeon to meet stocking requirements under the Keeyask *Environment Act* licence. Failure to satisfy those requirements would

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
result in sanctions against the Project from Manitoba Conservation and Water Stewardship, serious damage to the relationship with the Keeyask Cree Nation partners in the Project and general bad publicity. There are no alternative sources of genetically appropriate Lake Sturgeon to meet stocking requirements.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)

Other Alternatives Considered	NPV Benefits/(Costs)
A new hatchery on the lower Nelson River was contemplated however, cost estimates received from the consultant of $40-$50 million were much higher than expected.	

Risk Analysis
The risks associated with the Grand Rapids Fish Hatchery Expansion and Upgrade will be addressed through use of project contingency. A contingency of approximately 18% of the base estimate has been included in the overall project estimate. The following factors are not included in the base estimate, and may result in additional costs that would require the use of contingency: • Labour attraction and retention costs for remote northern work. • Cold weather construction. • Inherent risk of renovation work because of unforeseen site conditions that are not visible until construction begins.

Capital Budget Estimate

Summarize the total capital net cost for the project in thousands of dollars (per the CERs – see Excel table below). CPJs for Major items must be accompanied by at least draft CERs, while CPJs for Domestic items must be accompanied by final CERs.

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	899
2014/15	$	1,873
2015/16	$	4,696
2016/17	$	9,290
2017/18	$	6,751
Total	$	23,509

Proposed Schedule

A Stage 4 Engineering study has been completed. Stage 5 Engineering is assumed to begin in late 2014. Construction is expected to begin in the summer / fall of 2015 and to continue until the expected in-service date of March, 2018.

Related Projects

Keeyask Generating Station
Conawapa Generating Station (should it proceed)
Water Licenses and Renewals

Reference Documents

Keeyask Environmental Licence
Lower Nelson River Hatchery Phase 2 – Preliminary Design by HDR, Golder Associates and AECOM (2013)
Grand Rapids Hatchery: Phase 1 – Upgrade Study by HDR (2014)
Manitoba Hydro Satellite Nursery Design – Environnement Illimite Inc. (2014)

CAPITAL PROJECT JUSTIFICATION FOR

York Station
Banks 1, 3, 5 & Switchgear Addition

REVIEWED BY: Charles Steele, P.Eng. March 4, 2014
(Owning Dept Manager)

BUDGET $: (Total Net Cost)	$18,481,000
START DATE: (1st Cost Flow)	2013 03
IN-SERVICE DATE: (Last Major In-service Date)	2016 06

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

OWNING DIVISION: G13800 / Distribution E&C Winnipeg

I.M. NODE NUMBER: 1.1.3.6.49.1

RECOMMENDED FOR IMPLEMENTATION:

W.B.S. NUMBERs: P:21452

Owning Div. Manager: [signature] March 14, 2014

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

Business Unit V.P.: Brent Read 2014-03-26

PREPARED BY: Kristin Braid, P. Eng. K Braid, P.Eng. 2014 02 28

DATE PREPARED: 2013 12 30

REPORT NUMBER: 8446

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☒ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ YES ☒ NO

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

York Stn Banks 1, 3, 5 & S/G Add'n

Recommendation

Install 3-60kV-12.47kV, 10/13.33/16.67 MVA, transformers and three line-ups of switchgear for twelve additional feeder positions at the existing York (2) Station site for an estimated cost of $18,481,000 and an in-service date of 2016 06 30.

Project Scope

The scope of the project includes:

- Installation of three 60kV - 12.47kV, 10/13.33/16.67 MVA, 65C rated transformers with load tap changers.
- Installation of concrete foundations for the new transformers.
- Installation of three lineups of 2000A, Type 2B 12.47kV switchgear with an internal transfer bus for twelve additional feeder positions within the existing York (2) Station building.
- Protection/Metering equipment should be connected to the existing station SCADA system and communicate to SCC, with data to be made available on the Metering Web Application.
- Installation of bank cables from the new transformers to the new switchgear.
- Modifications to the existing 66kV bus structure at the station as required for connection of the new transformers.

The potential installation of new 12kV feeders from the new switchgear is not included in the scope of this project.

Background

York (2) Station was planned to support the long-term capacity needs in the downtown area. To date, four of the eight transformers, which the station was ultimately designed-for, are installed. While load growth is steady from its own customer load base, York (2) Station has also been used to manage loading at other downtown stations, accommodating several load transfers from both King (1) and Edmonton (21) Stations.

More recently, due to condominium development along Waterfront Drive and expansion at the Health Sciences Centre (HSC) complex, York (2) Station has also provided capacity support for Amy (6) and Sherbrook (14) Stations (via King (1) and Edmonton (21) Stations).

With the exception of York (2) Station, the 12kV stations in the downtown area are at 80% or more of their firm capacity, as per the chart below.

	Loading (MVA)	Firm Capacity (MVA)	% of Firm Capacity
King (1) Station 12kV	35.0	44.0	80%
York (2) Station 12kV	30.8	61.5	50%
Edmonton (21) 12kV	42.0	49.2	85%

Background

Continued residential and commercial development downtown, specifically in the Sports, Hospitality and Entertainment District (SHED) along Portage Avenue, is expected to yield increased 12kV loading that will exhaust the firm capacity at York (2) Station by the summer of 2016, and exceed firm capacity of the downtown 12kV distribution system in 2017.

Justification

York (2) Station was planned to support the long-term capacity needs in the downtown area. To date, four of the eight transformers the station was ultimately designed-for are installed. York (2) Station is the only station in the downtown area that can be easily expanded on the existing station site.

Installing three additional banks at this site will provide adequate capacity for load growth at York (2) Station and for the downtown area in general, including projected SHED development plans. However, if the SHED area does not develop as planned, the remaining capacity at York (2) Station will be available to use for future staged switchgear replacement at Edmonton (21) Station.

Additional capacity at York (2) Station will also allow for load transfers from King (1) Station, creating available capacity to extend King (1) feeders to the Health Sciences Centre complex area in 2016. This will provide a short-term solution for the deferral of William Station and avert capacity shortfall at Sherbrook (14) Station.

However, cascading load transfers from King (1) to York (2) Station to supply the Health Sciences Centre is not a long-term solution. Building the proposed Adelaide Station to replace King (1) Station, or building William Station, are more manageable long-term solutions. Increasing capacity at York (2) Station is the quickest way to ensure adequate capacity in the downtown area. Option Two considers installation of only two additional station banks at York, with the intent of providing the remaining capacity in the downtown area from the future Adelaide Station (proposed to be built by 2018). Option Two provides the minimum capacity to address downtown load growth. With the number of capacity and aging infrastructure issues that need to be addressed in the City of Winnipeg, it is not efficient to plan capacity increases so tightly. Although the initial capital costs for this option are lower than the Recommended Option, subsequent capacity projects will be required to meet the needs of the downtown area. It is also not economic to plan to re-mobilize labour in the same area every few years. Additionally, there will be limited capacity available for King (1) Station to support Sherbrook (14) Station in the HSC area. There is also risk that Adelaide Station, still an unapproved project, will not be completed before capacity at York (2) Station, and the downtown 12kV system as a whole, is out of capacity. This means that new load connections may be delayed until the station is completed.

Driver	Category	Sub-Category	Split	Amount
Reliability (F7)	Cap. Enhancement (FD)	New Asset Addition (HN)	100%	$ 18,481,000
			Total:	$ 18,481,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 5.4%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Install Three Additional Transformers and Switchgear Lineups at York (2) Station This option involves increasing the capacity of York (2) Station through addition of three new transformer banks and switchgear lineups with an in-service date of March 2016.	($14,792,000)

Other Alternatives Considered	NPV Benefits/(Costs)
Install Two Additional Transformers/Switchgear at York (2) Station; Supply Remaining Load from Proposed Adelaide Station This option considers the installation of the minimally-required infrastructure/equipment to meet load growth projections. It is not recommended as it does not provide sufficient long-term capacity at York (2) Station, nor can it be staged to supply the short-term downtown area capacity requirements.	($10,878,000)

Risk Analysis

This project will compete for the same planning, design and construction resources as other approved station projects, and the in-service date of this or those other projects may be affected.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	0
2013/14	$	103
2014/15	$	6,222
2015/16	$	11,578
2016/17	$	577
Total	$	18,481

Proposed Schedule

Design & Material Order – March 2014 – December 2014
Switchgear Arrival – May 2015
Transformer Arrival – June 2015
Complete Equipment Installation – February/March 2016
Commissioning – June 2016

Related Projects

None.

Reference Documents
Distribution Planning Study - DPW W13-03: York (2) Station Bank 1, 3, 5 & Switchgear Addition

CAPITAL PROJECT JUSTIFICATION FOR

Southern AC System Breaker Replacements

REVIEWED BY:
(Owning Dept Manager) 2014-07-15

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Designing Division:

Financial: 2014.07.11

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: July 11, 2014

Business Unit V.P.: 2014.07.14 FOR SHANE MAILEY

BUDGET $: (Total Net Cost)	$14,693,000
START DATE: (1st Cost Flow)	2014 03
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	Mult - 2016 11
RISK MATRIX/ BUSINESS CASE TIER:	Tier 1 (1240 pts)
INVESTMENT REASONS:	Employee Safety (76%) Capacity Enhancement (20%) Public Safety (4%)

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.1.2.3.62.1

W.B.S. NUMBERS: P:21597

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Chad Gislason – Project Owner CG 2014/07/1
Ty Nguyen – Project Manager TN

DATE PREPARED: 2014 04 01 2014.07.1.

REPORT NUMBER: TM-2011/05 & TM-2012/02

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☒ Safety	☐ Customer Service
☐ System Supply	☐ Efficiency
☒ System Reliability	☐ Environmental

NERC COMPLIANCE * ☒ **YES** ☐ **NO**

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Southern AC System Breaker Replacements

Recommendation

Replace fifteen 230kV circuit breakers at Dorsey Station, two 115kV circuit breakers at McPhillips Station and one 66kV circuit breaker at Boyd Station, due to increasing fault levels. Total Net Cost is estimated at $14,693,000 for a staged in-service ending in November 2016.

Project Scope

Dorsey Station (estimated Gross cost = $12,383,000)

- Salvage fifteen 230kV breakers (R19, R25, R29, R35-R39, R44-R47, R51, R53 and R54) and replace with fifteen 4000A, 63kA live tank breakers.
- Salvage the current transformer (CT) associated with breaker R38 and replace with 4000A 63kA stand-alone dry-type CT.
- Salvage connection protection on valve group transformers T31, T32, T41 and T42 and replace with dual redundant protection systems.
- Change CT ratio associated with 230kV line A4D to 2000:5.
- Salvage and replace eight AC/DC zone boxes ZB5 to ZB12.
- Upgrade the following 230kV rigid bus sections:
  - Filter banks F1 to F6 – salvage existing 2.5" schedule 40 rigid bus and replace with 3.5" schedule 80. Salvage post insulators for the rigid bus and replace with Extra Heavy type insulators.
  - Breakers R8, R9, R18, R22, R28 and R29 – salvage existing 3.0" schedule 40 rigid bus and replace with 3.5" schedule 80. Salvage post insulators for the rigid bus and replace with Extra Heavy type insulators.

McPhillips Station (estimated Gross cost = $957,000)

- Salvage two 115kV breakers (B8H and B9H) and replace with 2000A 40kA dead tank breakers complete with internal CTs.
- Salvage Bank 8 and Bank 9 ground-over-current relays 51G and 87G and replace with one digital protection relay.

Boyd Station (estimated Gross cost = $393,000)

- Salvage one 66kV breaker (H252) and replace with a 3000A 40kA dead tank breaker complete with internal CT.

The total Gross estimate for this complex is $13,733,000. With forecast escalation estimated at $311,000 and capitalized interest estimated at $649,000, the Total Net Cost is estimated at to $14,693,000.

Background

System enhancements implemented to meet the growing load demand in Manitoba, as well as the installation of Bipole III, will drive short circuit levels close to or exceed the interrupting capability of several breakers in the Manitoba Hydro Southern AC system.

Background

The fifteen breakers identified for replacement at Dorsey are currently at 96% of their rating, while the two at McPhillips are at 99% of their rating and the one at Boyd is at 93% of its rating. Once Bipole III goes into service, these breakers will be well beyond 100% of their rating. The choice of converter technology for the Bipole III HVDC transmission scheme (i.e., LCC or VSC) does not change the need to replace these breakers.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Proceeding with this project addresses several issues at Dorsey, McPhillips and Boyd stations that will arise as a result of Bipole III and the increasing short circuit levels:

- the interrupting capability of existing breakers;
- the ability of existing bus work to handle the increase fault levels; and
- the ability of existing protection systems to reliably isolate a fault.

In addition, several sections of rigid 230kV bus at Dorsey will be mechanically underrated. Under fault conditions, the mechanical stress may cause the bus and/or the support insulators to fail. As well, connection protection on the Bipole II valve group transformer 230kV bus section was found to have current transformer saturation and thermal issues with the increased fault current levels. These two issues would result in misoperation for some external faults and in-zone faults.

Replacing these breakers, upgrading the bus work and replacing the connection protection would improve the safety at all three of these stations. Without replacement, under certain fault conditions the existing equipment would fail catastrophically, which would expose employees and the public to a high-risk incident. The project therefore contributes to Manitoba Hydro's Operational Excellence with respect to safety.

Additionally, these upgrades will provide better system reliability. Without the upgrades, fault levels would have to be lowered in order to safely operate the system. To lower the fault levels, synchronous condensers at Dorsey and/or Riel would have to be shut down. However, in order to shut down these synchronous condensers, the power output of the DC system (Bipole I, II and III) would have to be reduced. The project therefore contributes to Manitoba Hydro's Operational Excellence with respect to customer value.

It should be noted that the increase in fault levels that will occur when Bipole III is placed into service will also result in three 66kV breakers at King Station exceeding their interrupting capability. However, Distribution Engineering & Construction plans to replace King Station with a new Adelaide Station. Therefore, in lieu of replacing these three breakers, operating restrictions will be put in place to reduce fault current levels until King Station is de-commissioned.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Safety	Employee Safety	Asset Improvement	76%	$11,167,000
Reliability-Load Related	Capacity Enhancement	Asset Improvement	20%	$ 2,938,000
Safety	Public Safety	Asset Improvement	4%	$ 588,000
				$14,693,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	%	For current corporate rates see G911 For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Replace 18 breakers at Dorsey, McPhilllips and Boyd Stations.	($12,275,000)

Other Alternatives Considered	NPV Benefits (Costs)
No other alternatives were identified.	

Project Risk Analysis

A total of $1.8M for Contingency has been included in the project estimate, which is approximately 15% of the base estimate. The breakdown between projects is as follows:

Dorsey Station – $1.7M to cover these potential risks:
- Variation in electrical consulting prices, design changes (e.g., requirement of new communications rack / cubicle and fibre optic equipment, piled-foundations for breakers, etc.), civil and electrical material price escalation and overtime ($607k).
- Four breakers may need to be "T" type instead of candela-type as provided for in the estimate, depending on analysis to be provided by a manufacturer ($595k).
- Civil construction, overhead line construction, insulation testing and electrical construction taking place in the winter months, and field modifications for the rigid bus replacements ($477k).

McPhillips Station – $83k to cover these potential risks:
- Variation in electrical consulting prices, design changes, material price escalation and overtime ($43k).
- Civil and electrical construction taking place in the winter months ($36k).

Boyd Station – $28k to cover these potential risks:
- Variation in electrical consulting prices, design changes and material price escalation ($15k).
- Electrical construction work taking place in the winter months ($10k).

The breakers needs to be replaced prior to the start of commissioning of Bipole III, which is due to commence six months ahead of its in-service date.

Capital Budget Estimate

The annual and total net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ 1
2014/15	$ 2,632
2015/16	$ 7,231
2016/17	$ 4,669
2017/18	$ 160
Total	$ 14,693

Proposed Schedule

Dorsey Station (fifteen 230kV breakers):

Project Start	March 2014
Breaker Procurement	Ordered: June 2014, Delivered: April 2015
Detailed Design	June 2014 to May 2016
Material Procurement	June 2014 to August 2016
Construction	October 2014 to November 2016
Commissioning	March 2015 to November 2016
In-service of seven new breakers	November 2015
In-service of eight new breakers	November 2016

McPhillips Station (two 115kV breakers) and Boyd Station (one 66kV breaker):

Project Start	June 2015
Breaker Procurement	Ordered: July 2015, Delivered: May 2016
Detailed Design	October 2015 to June 2016
Material Procurement	January to August 2016
Construction	September to November 2016
Commissioning	October to November 2016
Boyd in-service	October 2016
McPhillips in-service	November 2016

Related Projects

Breaker Replacements for Bipole III (P:21201).

Reference Documents

- System Planning Technical Memo, TM-2011/05 – Winnipeg Area Circuit Breaker Short Circuit Capability Assessment Following the Completion of the Riel Line Commutated (LCC) Based Converter Station/Bipole III Project (2017-2025), dated 2011 11 09
- System Planning Technical Memo, TM-2012/02 – Winnipeg Area Circuit Breaker Short Circuit Capability Assessment Following the Completion of the Riel Voltage Source Converter (VSC) Based Converter Station/Bipole III Project (2017-2025), dated 2012 02 27.
- Distribution Engineering Report, DEW-W14-01 – Adelaide Station, dated 2014 03 28.

Reference Documents
– Distribution Engineering IOM, Recommendation to Cancel King Station 66kV Breaker Replacement (Graham Verch), dated 2013 09 20. – Station Design IOM, Protection System Upgrades to be Included in the Dorsey 230kV Breaker Replacement Project, file# 65020-01075, dated 2014 03 14. – Station Design Department, Design Basis Memorandum for Dorsey Station 230kV Switchyard Bus Fault Level Study, dated 2014 04 09.

CAPITAL PROJECT JUSTIFICATION FOR

JENPEG UNIT 1 FIRE REHABILITATION

REVIEWED BY:
(Owning Dept Manager)
2014 02 27

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division: P. Eng 2014 02 27

Financial Department:
(if over $1 million)
2014 02 27

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 02 27

Business Unit V.P.: 2014-03-02.

BUDGET $: (Total Net Cost)	$14,000,000
START DATE: (1^{st} Cost Flow)	2014 03
IN-SERVICE DATE: (Last Major In-service Date)	2015 11
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: Generation South

I.M. NODE NUMBER: 1.1.1.3.7.4

W.B.S. NUMBERs: P:21120

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J. Austman JTA J.G.

DATE PREPARED: 2014 02 21

REPORT NUMBER: 4432

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☒ System Supply
- ☐ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☐ **YES** ☒ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Jenpeg Unit 1 Fire Rehabilitation

Recommendation
Approve a budget of $14.0 M to repair the fire damage to Jenpeg Unit 1, perform a mechanical condition assessment of high risk components and return the Unit to service.

Project Scope

The scope of the project includes the design supply and installation of the following components.

- generator breaker and terminal cubicle instrument transformers/apparatus
- excitation system
- generator control (sequencer controls), metering and operator interface
- generator and transformer protection
- generator disconnect
- generator breaker
- governor control head
- unit annunciator
- deluge controls
- rotor turning system and turning bridge
- restoration and repair of the Series 5 unit PLCs.
- AC isolated phase bus
- line side generator CTs and PTs
- generator step up transformer interfacing
- restoration of the U1 interlocking scheme
- powerhouse tailrace wall repair

In addition, the scope also includes the following mechanical items in order to gain condition assessment information for future overhaul planning. Non-intrusive methods will be utilized, where appropriate, to minimize cost, time and damage risks:

- Outer / Inner Wicket Gate Ring Eccentricity Survey
- Water passage Inspection
- Bearing Inspections (#1, 2, 3)
- Runner Inspection
- Generator Shaft Non Destructive Examination (NDE)
- Turbine Shaft NDE
- Operating Linkages & Bushing Inspection
- Verify Manual Greasing Operation
- Oil Head Inspection
- Water Head Inspection
- Pedestal Inspection
- Bulb Internal and External Connection NDE
- Bearing Cooler Piping Inspection
- Heat Exchanger Piping Inspection
- DIW System Inspection

Project Scope

- Discharge Ring & Wicket Gate Rings, NDE & Thickness Checks
- Exposed Water Passage NDE & Thickness Checks
- Operating Ring Inspection
- Rotor (Mechanical)
- Stator (Mechanical)
- Thrust Bearing Inspection
- Hatch NDE (Bulb Cover)
- Wicket Gate NDE

Cost Category	Amount in Millions	
Construction/Material	$	8.7
Accommodations/Travel	$	1.4
Site Labour	$	1.0
Project Management	$	1.0
Engineering	$	0.9
Interest	$	0.6
Escalation	$	0.4
Grand Total	**$**	**14.0**

Background

On Sunday, November 4, 2012, an electrical fire occurred at the generator breaker in the Jenpeg Unit 1 generator terminal cubicle (GTC) located at elev. 691.0'. The fire was contained to the area surrounding the GTC, but the majority of the equipment in this location requires a complete replacement due to the resulting damage. Unit 1 is currently on a forced outage due to the damage sustained during the fire.

Given that the unit is currently out of service a number of opportunity items have been identified in order to perform condition assessment or repairs. Major disassembly work with respect to the water passage, turbine and generator are explicitly not included in this CPJ's scope of work, however, there are known failure modes associated with the Jenpeg units that may need to be investigated further. For example, Jenpeg Units 4 and 6 have experienced restoring rod failures. Replacing this component requires dismantling the water passage and turbine components. The total cost of Jenpeg Unit 4 restoring rod replacement work is approximately $8 M and requires upwards of 8 months of construction to complete.

Each unit at the Jenpeg Generating Station produces 28 MW. Currently, outage costs are estimated at $11,000 per day.

The rehabilitation scope outlined above will be initiated and followed out with the global objective of returning all equipment to service for safe and reliable operation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Returning Jenpeg Unit 1 to service will return 31.1 MVA to Manitoba Hydro's bulk electric system. Approximately 28 MW would be available for export and domestic load. In order to return the unit to service, the damage caused by the fire must be repaired. The outage costs are estimated to be $11,000 per day (~$4.0 M per year). Given the estimated project cost, the project will pay for itself within 4 years. The project supports the following corporate goals: • Provide a reliable and dependable supply of power to meet all customers' requirements - *continuously improve generating station reliability and capability as required to optimize operations of the system* • Optimize operations, exports and development to minimize net cost to Manitoba customers - *Reduce duration of outages*

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.4%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Repair the fire damage to Jenpeg Unit 1, perform a mechanical condition assessment of high risk components and return the Unit to service.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis
Scope creep: Due to the expedited nature of this project, there will be scope risk as the bounds of the project are not fully known nor is it fully defined to the vendors. This will be managed through the contract negotiation and change management processes. After the fire occurred, the transformer was inspected and passed; however, it experienced a significant fault which carries future risk of an in-service failure. From a mechanical perspective, there are condition assessment activities to be done. As with all overhauls, disassembling a 35 year old machine may reveal damage or deterioration that must be fixed in order for the unit to be put safely back in service. Jenpeg Unit 4 restoring rod replacement project is currently underway which may identify further areas of concern on Unit 1. Given the current level of mechanical engineering resources available, there is a risk that condition assessment efforts may become critical path. Further to this risk, if a component, such as the restoring rod, requires replacement, the total project cost and duration will increase. For reference, Jenpeg Unit 4 resorting rod replacement is estimated to be $8 M and requires upwards of 8 months of construction time to complete. Depending on the timing of the discovery, this may delay the in service date of the unit. Also, further Mechanical Engineering resources would be required to support the additional scope.

Risk Analysis

Major civil works associated with beams and slabs are not included in this request but could form part of the scope if they are found to be in poor condition during execution of the work. Only minor cladding repair is included in this estimate.

An internal Scope Change Request process, with formal approval signoff cycle, is currently in place to mitigate and maintain the risk of adding unnecessary or low-priority work to the project.

Major contracts award: A contract must be issued in a timely manner for the design, supply and installation of the electrical equipment required to return the unit to service as scheduled. The evaluation matrix takes into consideration the amount of time that it may take to resolve technical and commercial issues. This is intended to minimize the total cost impact to Manitoba Hydro.

Capital budget constraint: The availability of capital funding is limited for the next few years. The overall Generation Operations capital budget will need to be managed to ensure higher priority jobs are completed first. It is expected that because this unit has failed that it will be included in the recommended portfolio.

Availability of internal resources: Internal resources for Project Management, design review and condition assessment must be secured and made available in a timely manner. Staff turnover will have to be managed to ensure it does not significantly impact the course of this project work. Given that the majority of the work will be done by a contractor, this risk is minimized.

Competing projects: Other projects, such as Pine Falls Unit 2, Jenpeg Unit 4, etc., may take precedence and consume resources allocated to this overhaul. In addition, there may be crane conflicts between Jenpeg unit 1 fire repairs and Jenpeg unit 4 restoring rod replacement projects which will affect schedule.

Accommodations: Jenpeg Unit 4 Restoring Rod Repairs are currently underway and the Jenpeg Camp expansion project will not be completed until Fall 2014. To minimize this risk, RFP 038330 stated that Manitoba Hydro has limited accommodations and the contractor will have to supply their own.

Capital Budget Estimate

Summarize the total capital net cost for the project in thousands of dollars (per the CERs – see Excel table below). CPJs for Major items must be accompanied by at least draft CERs, while CPJs for Domestic items must be accompanied by final CERs.

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2013/14	$	112
2014/15	$	7,242
2015/16	$	6,638
2016/17+	$	-
Total	$	13,992

Proposed Schedule

RFP 038330 Contract Award	March 2014
In Service Date	September 30, 2015

Related Projects

Jenpeg Unit 4 Restoring Rod Replacement Project

Reference Documents

J. Kleinsasser: "Conceptual Design Report for Jenpeg Unit 1 Fire Repairs". November 26, 2013

CAPITAL PROJECT JUSTIFICATION FOR

SOURIS EAST TRANSFORMER CAPACITY ENHANCEMENT

REVIEWED BY:
(Owning Dept Manager) 2014/01/31

NOTED BY:
(if applicable)

Coordinating Division: 2014/05/29

Constructing Division:

Designing Division:

Financial: 2014.01.17

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 05 29

Business Unit V.P.: 2014 06 02

BUDGET $: (Total Net Cost)	$11,302,000
START DATE: (1st Cost Flow)	2016 04
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	2019 04
RISK MATRIX/ BUSINESS CASE TIER:	Tier 3 (700 Points)
INVESTMENT REASONS:	Capacity Enhancement (100%)

OWNING DIVISION: Transmission Planning & Design

I.M. NODE NUMBER: 1.1.2.4.27.1

W.B.S. NUMBERS: P:15989

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Joshua Shewchuk, Project Owner 2014/01/
Locky Miller, Project Manager 2014/01/2

DATE PREPARED: 2013.09.19

REPORT NUMBER: SPD 2012/03

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE * ☐ YES ☒ NO

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Souris East Transformer Capacity Enhancement

Recommendation
Establish a new Base Capital-Core item for the installation of a 230-66kV transformer at Souris East Station, plus associated equipment. The total net cost is estimated at $11,302,000, for an in-service date of April 2019.

Project Scope

The project includes the following:

- Purchase and installation of a 230-66kV, 57/76/95 MVA transformer in the Bank 2 position, with an OLTC range and a de-energized tap changer range compatible with existing Bank 1.
- Installation of two 230kV circuit breakers, one 66kV circuit breaker, one 66kV grounding bank, two 66kV station service transformers, and associated equipment for termination of the transformer.
- Installation of remote control and metering with a SCADA system.

The total gross cost is estimated at $9,747,000. Forecast escalation calculates at $928,000 and capitalized interest calculates at $627,000, for a total net cost of $11,302,000. The projected in-service date is April 2019.

Background

A report was compiled for the Enbridge Pipelines Clipper Project (SPD 2007/17) which highlighted loading issues present at Souris East Station. Historically, Souris East Station was provided alternate supply by 115-66kV transformation from Brandon Victoria Station; however, loading has grown to the point that Brandon Victoria can no longer reliably supply the total Souris East Station load without 66kV voltage concerns. The Enbridge report had recommended that a second 230-66kV transformer be installed at Souris East Station to support the new Enbridge load on the 66kV system. Based on new loading information, it was later determined that the requirement for a new transformer at Souris East shouldn't be linked directly to the new Enbridge load, since Souris East Station did not even have firm transformer capacity.

A new study was conducted and a new report written (SPD 2012/03) to investigate the capacity at Souris East Station. The new report identified the need to install a 230-66kV power transformer at Souris East Station to provide firm transformation. Provision of firm transformation is the responsibility of the Transmission provider and hence not eligible for customer contributions.

The study specified an in-service date of October 2015 for the additional transformation. However, some of the key resource areas needed on this project are already fully committed on other higher-priority projects over the next several years, such that the start date for this project has been assumed to occur no earlier than 2016/17. Allowing approximately 22 months to specify and deliver the transformer and 14 months for installation and commissioning, the estimated in-service date is April 2019.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The absence of firm transformation at Souris East Station could cause outages to customers in the area during a transformer outage. The outage could last several weeks, until a spare transformer could be brought in from Winnipeg and connected in the station. Deferral of this project could place customers at risk of no supply. Repair of a failed transformer could take up to two years.

Additionally, although not a direct driver for the capacity enhancement, the Enbridge load supplied by Souris East 230-66kV station is being investigated to increase from a contract of 13.3 MVA up to a new contract of 22.9 MVA. It's expected this would not have an effect during normal operation, but a loss of the existing Souris East transformer could result in additional load experiencing an extended outage.

The planning studies and recommended capacity enhancement are based on the existing contracted load and not the realized load for Enbridge.

The only alternative that was considered was a different station layout for the new bank which would have involved a station expansion. This alternative was rejected, as it would be more expensive and likely would have taken longer.

This project supports the Corporate goal of "Provide exceptional customer value" and the Transmission goal of "Provide customers with reliable power".

Capital Investment Categorization:
See link for instructions: http://t.hydro.mb.ca/tclm/tp/Capital%20Project%20Justification%20CPJ/Capital%20Investment%20Categorization.doc

Driver	Category	Sub-category	Split	Amount
Reliability: load-related	Capacity Enhancement	New Asset Addition	100%	$11,302,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	5.40%	For current corporate rates see G911 For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Enhance transformer capacity within existing station layout	($6,253,000)

Other Alternatives Considered	NPV Benefits (Costs)
Enhance transformer capacity with station expansion	($7,381,000)

Project Risk Analysis

A total contingency of $857,000 (10% of the gross estimate) has been included to cover potential cost increases associated with design changes, material cost escalations, and unfavorable weather during construction.

Capital Budget Estimate

The annual and total net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	–
2014/15	$	–
2015/16	$	–
2016/17	$	377
2017/18	$	6,452
2018/19	$	3,308
2019/20	$	1,164
Total	$	11,302

Proposed Schedule

The key milestones are as follows:

Activity		Dates
Project Kick-off		May 2016
Design	• Protection • Automation & Controls • Structures, Equipment & Grounding • Civil • Communications	May 2016 - Jan 2017 Jan 2017 - Nov 2017 Sep 2017 - Jan 2018 Oct 2017 - Feb 2018 Dec 2017 - Mar 2018
Order Apparatus		May 2016 - Sep 2016
Manufacture & Delivery	• Power Transformer • Other Apparatus • Civil Material • Communications Material	Sep 2016 - Mar 2018 Sep 2016 - Sep 2017 Feb 2018 - Jul 2018 Jan 2018 - Mar 2018
Installation	• Communications • Civil • Electrical • Commissioning	Mar 2018 - Jun 2018 Jul 2018 - Sep 2018 Sep 2018 - Jan 2019 Feb 2019 - Apr 2019

Related Projects

None

Reference Documents

1) SPD 2007/17, "Enbridge: Clipper Project Load Interconnection Facility Study", J. Drew, approved 2009 12 18.
2) SPD 2012/03, "Souris East Transformer Capacity Enhancement", J. Shewchuk, approved 2012 04 09
3) Interoffice memorandum, "Power Delivery to Souris Enbridge Station," from A. Silk to M. Rheault dated 2014 02 07.
4) Email from M. Adamkowicz to C. Nieuwenburg dated 2014 05 28 with attached interoffice memorandum, "Contingency Suppy of Souris Enbridge East 230kV Station During Long-Term Outages" from M. Rheault to M. Adamkowicz, dated 2014 05 21.

CAPITAL PROJECT JUSTIFICATION

FOR

JPG UNIT 4 PARTIAL MECHANICAL OVERHAUL

REVIEWED BY:
(Owning Dept Manager)
2014/06/03

NOTED BY:
(if applicable)

Coordinating Division: S.G. 2014 06 04

Constructing Division:

Financial Department: 2014/06/05
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 06 04

Business Unit V.P.: 2014-06-05

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- [ ] Safety
- [x] System Supply
- [ ] System Reliability
- [ ] Customer Service
- [ ] Efficiency
- [ ] Environmental

NERC COMPLIANCE*: [ ] YES [x] NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$11,232,955
START DATE: (1st Cost Flow)	2013 04
IN-SERVICE DATE: (Last Major In-service Date)	2015 03
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	
OWNING DIVISION:	Generation South
I.M. NODE NUMBER:	1.1.1.3.7.3
W.B.S. NUMBERs:	P:20045
MAJOR ITEM [x]	**DOMESTIC ITEM** [ ]
PREPARED BY: AF	O.A. Ramirez
DATE PREPARED:	2014 05 13
REPORT NUMBER:	4313
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Jenpeg Unit 4 Partial Mechanical Overhaul

Recommendation

Approve a budget of $11.2 M to refurbish the failed turbine restoring rod in Jenpeg Unit 4, perform mechanical inspections of high risk components and return the Unit to service. Justify additional funds as required for necessary refurbishments resulting from the inspections.

Project Scope

The scope of the project includes :

- Unit disassembly and removal of runner
- Refurbishment of the generator and turbine restoring rod
- Unit reassembly and commissioning
- Documented procedures and project plan for future failures of remaining units.

In addition, the scope also includes the following inspections in order to ensure components meet their estimated useful life. Inspected components will either be confirmed fit for service or refurbished as required to ensure continued operation to the next major overhaul. These refurbishment costs are not currently included in this project and will be added scope requiring justification. These inspections will also provide valuable information for future overhaul planning of other units. Non-intrusive methods will be utilized, where appropriate, to minimize cost, time and damage risks:

- Outer / Inner Wicket Gate Ring Eccentricity Survey
- Bearing pedestal grounding inspection (#1, 2)
- Runner Inspection
- Generator Shaft Non Destructive Examination (NDE)
- Turbine Shaft NDE
- Verify Manual Greasing Operation
- Oil Head Inspection
- Water Head Inspection
- Bulb Pedestal Inspection
- Bulb Internal and External Connection NDE
- Bearing Cooler Piping Inspection
- Heat Exchanger Piping Inspection
- DIW System Inspection
- Exposed Water Passage NDE & Thickness Checks
- Rotor Inspection(Mechanical)
- Stator Inspection (Mechanical)
- Hatch Cover rehab (Bulb Cover)
- Wicket Gate NDE inspection procedure

Project Scope

Cost Category	Amount in Millions	
Construction/Material	$	4.1
Mechanical assessment	$	2.0
Accommodations/Travel	$	0.7
Site Labour	$	0.6
Project Management	$	1.2
Engineering	$	1.4
Interest	$	1.0
Escalation	$	0.2
Grand Total	**$**	**11.2**

Background

Following a head tank oil loss scenario in 2011 of the Unit 3 and 4 governor system it was determined that there was a serious problem with the oil head of Unit 4. Upon further investigation the oil head was not the cause of the oil leak but the turbine restoring rod had completely fractured.

Site mechanics removed the generator restoring rod with a portion of the broken turbine restoring rod via the upstream shaft opening once the oil head and water head were disassembled. However, the remaining portion of the turbine restoring rod cannot be removed until the turbine hub is removed.

Given that the unit is currently out of service a number of condition assessments have been identified and will be carried out in order to provide information to the Generation Operations Asset Management program to aid in the planning of future Jenpeg overhauls. These overhauls will be near $100M in Capital investments and require information to help set the scope and schedule.

Each unit at the Jenpeg Generating Station produces 28 MW. Currently, outage costs are estimated at $11,000 per day. The condition assessments will also be used to identify risk of failure items on all units to help minimize or even avoid unplanned outages due to failure of critical components.

The repair scope and condition assessments outlined above have begun (April 2013) and all costs to date have been charged to a domestic capital number and will be transferred to a Major Capital Item pending approval of this CPJ. This work will continue and be completed with the global objective of returning all equipment to service for safe and reliable operation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Returning Jenpeg Unit 4 to service will return 31.1 MVA to Manitoba Hydro's bulk electric system. Approximately 28 MW would be available for export and domestic load. In order to return the unit to service, the restoring rod must be refurbished. The outage costs are estimated to be $11,000 per day (~$4.0 M per year).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
The inspections will be a capitalized expenditure as they meet the following anticipated IFRS guidelines: • Occur at least once over the life of the asset (At least three years apart); • Are completed within an 18 month time period; • Cost incurred are greater than $500,000 • Are engaged to ensure that componentized assets meet their estimated useful lives The project supports the following corporate goals: • Provide a reliable and dependable supply of power to meet all customers' requirements - *continuously improve generating station reliability and capability as required to optimize operations of the system* • Optimize operations, exports and development to minimize net cost to Manitoba customers - *Reduce duration of outages*

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.4%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Refurbish the Jenpeg Unit 4 restoring rod, perform a mechanical condition assessment of high risk components and return the Unit to service.	

Other Alternatives Considered	NPV Benefits/(Costs)
Consideration was given to completing the repair only and not the condition assessments, thereby reducing the total project cost by $2M. However, this was not recommended by Generation South as the Condition Assessment information is critical to Generation Operations Asset Management Program, to minimize the risk of future failures of Jenpeg Units and to help set the scope and schedule for the Jenpeg overhaul program which is currently estimated to be near $100M.	

Risk Analysis
<u>Scope creep</u>: From a mechanical perspective, there are condition assessment activities to be done. As with all major work, disassembling a 35 year old machine may reveal damage or deterioration that must be fixed in order for the unit to be put safely back in service. An internal Scope Change Request process, with formal approval signoff cycle, is currently in place to mitigate and maintain the risk of adding unnecessary or low-priority work to the project. <u>Capital budget constraint</u>: The availability of capital funding is limited for the next few years. The overall Generation Operations capital budget will need to be managed to ensure higher priority jobs are completed first. It is expected that because this unit has failed that it will be included in the recommended portfolio.

Risk Analysis

Availability of internal resources: Internal resources for Project Management and design review for out of scope items must be secured and made available in a timely manner. Impact of not securing internal resources will be schedule delays. Staff turnover will have to be managed to ensure it does not significantly impact the course of this project work. Site resources will be used for some condition assessments and will be required for commissioning. These resources are limited and add risk to the project.

Competing projects: There may be crane conflicts between Jenpeg Unit 1 Fire Restoration and Jenpeg unit 4 Partial Mechanical Overhaul projects which could affect schedule. Jenpeg Shaft seal replacement project is underway and nearing completion; some work will overlap with Jenpeg Unit 4 repair work. Other major projects are scheduled to begin this year and include: Great Falls U4 Rerunnering, Grand Rapids U1 exciter replacement, Pine Falls U2 rewind.

Accommodations: Accommodations are limited at Jenpeg and the Jenpeg Camp expansion project will not be completed until Fall 2014. Accommodations will have to be carefully coordinated for all Jenpeg projects.

Environmental: Workplace health and safety regulations and guidelines must be met during project. Lead is known element used throughout Jenpeg construction. Lead handling and dust abatement in addition to lead disposal must be addressed and each comes with added cost to the project.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars). The Domestic Capital actual cost to date is $1,917,237 which is included in the 2013/2014 estimate below:

Prev. Actuals	$	1,917
Over/Under Expend	$	(275)
2014/15	$	8,083
2015/16	$	1,508
Total	$	11,233

Proposed Schedule

ABCO contractor start date	Jan 21 2014
In Service Date	March 27, 2015

Related Projects

Jenpeg Unit 4 Restoring Rod Replacement Project
Jenpeg Unit 1 Fire restoration project
Jenpeg Shaft Seal replacement project

Reference Documents

00198-41138 U4 Restoring Rod Failure EC recommendation 2012_02_10

CAPITAL PROJECT JUSTIFICATION FOR

GEN S ROOF REPLACEMENT PROGRAM

REVIEWED BY:
(Owning Dept Manager)
2014/05/30

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/06/05

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/06/04

Business Unit V.P.: 2014/06/12.

BUDGET $: (Total Net Cost)	$6,338,944
START DATE: (1st Cost Flow)	2014 01
IN-SERVICE DATE: (Last Major In-service Date)	

OWNING DIVISION:	G12500 / Generation South
I.M. NODE NUMBER:	1.1.1.3.13.1
W.B.S. NUMBERs:	P:21842
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	TINHOLT, MIKE
DATE PREPARED:	2014 05 14
REPORT NUMBER:	4298
FILE NUMBER (Optional):	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☒ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ YES ☒ NO

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
GEN S ROOF REPLACEMENT PROGRAM

Recommendation
Replace the roof elevations based on the recommendations provided by Pinchin Environmental in the roof inspection reports and the roofing condition assessments. Roofs to be replaced from worst case to best over the course of the next eight fiscal years at approximately one roof per year. All roof elevations will be replaced unless noted otherwise. These exceptions may include but not limited to roofing areas that are 15 years old or newer or have minimal signs of degradation.

Project Scope
Replace all roof systems in disrepair with new modern roof systems that will provide 30+ yrs of reliable service. This work will also include the removal of any and all redundant roofing structures or protrusions to prevent future leaks. Related items to include, but are not limited to: new pitch pans, flashings, roof drains/plumbing, scuppers, curbs, formed metal storm collars and all related sealing. This work includes all elevations at Jenpeg, Grand Rapids, and Bunker Bay 5 at Brandon GS.

Background

In 2011, Pinchin Environmental was contracted to inspect and determine the quality of the roofing systems throughout Generation South. Reports were generated by the consultant who described most roofs within Gen South as being Marginal to Poor and some had even failed. Some of our powerhouse roofs, although in reasonable condition, contain environmentally and structurally harmful roof construction such as phenolic foam insulation (acid leachate) and coal tar pitch (heavy petroleum product) that under certain conditions can be harmful to the building or its occupants.

The roofs were scaled on a weighted points system and given a score between zero and ten, zero being complete failure and ten being new condition. The draft outlook provides the schedule for repairs based on condition assessment scores provided by the consultant.

Jenpeg (proposed for 2015/16), has an average roof rating of poor (2.25). It has several roof areas that have standing water due to poor drainage and have resulted in widespread vegetation growth. Expansion joints and related metal coverings have deteriorated and showing signs of water damage. Water leaks into the Powerhouse have to potential to contact electrical equipment.

Grand Rapids (proposed for 2016/17) Powerhouse and Administration Building are in poor condition, 2.75 and 3.25 respectively. They have visible standing water on the membranes and between the vapour barrier and insulation. Vegetation growth can be widely seen on these two roof areas. No major maintenance has been done to the roof areas and repairs are needed to maintain service.

Brandon (proposed for 2017/18) has two elevations of concern: the admin wing (3.5 poor) and Bunker Bay 5 (1.5 failed). Both elevations have presence of ponding water within the roof membranes. The admin wing has a considerable amount of vegetation growth and shows signs of water leakage from underside of roof deck and is visible on the ceiling tiles. The powerhouse also has water infiltration through bunker bay 5 membranes evident by the staining on the roof deck, walls and floor.

Justification

Many of the roof systems within Gen South are beyond their service life and are experiencing major leaks and requiring constant repairs. In most cases the repairs performed are ineffective due to the condition of the overall roof areas and either the leaks continue despite the repairs, or the water finds another area to infiltrate. Many of the leaks are in critical areas of the powerhouses including high tension areas and control equipment. Failure to replace the roofs in a timely manner may result in a loss of generation due to electrical faults, mold growth within our powerhouses, increased deterioration of structural members, or personal injury due to slips, trips and falls.

Given the failing and near failure conditions the risk frequency is “High” while the consequnce is considered as “Low” to “Medium” in the event of a electrical in our electrical equipment the over risk is rated as “Not Desirable to “Unacceptable” on the risk matrix.

This project aligns with the Gen South and Power supply goals: "To provide reliable and dependable supply of power to meet all customers' requirements" and "Improve safety, health and wellness in the work environment".

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Recommend to proceed with the roof replacement program. “Do Nothing” was not considered a viable option as the roofs have exceeded their serviceable life and further deterioration could lead to unsafe working conditions and increased risk of damage to generating station assets.	

Other Alternatives Considered	NPV Benefits/(Costs)
“Do nothing” was not considered a valid option because the roofs have exceeded their serviceable lives.	

Risk Analysis

Scope Creep (High)
Schedule Delays (Medium)
Increase Costs (Medium)
Working at Heights (Low)
Environmental Impact (Low)

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	-
2014/15	$	52
2015/16	$	2,366
2016/17	$	2,107
2017/18+	$	1,814
Total	$	6,339

Proposed Schedule

Station In-service dates:
2016/03/31 Jenpeg
2017/03/31 Grand Rapids
2018/03/31 Brandon

Related Projects

1991 - GS ROOF INSPECTION PROGRAM
4560 - GS FORECASTED ROOF REPLACEMENT PROGRAM
4577 - SF ROOF REPLACEMENT

Reference Documents

http://hrcs.hydro.mb.ca/its/aip/Documents/Draft/4298 Gen South Roof Replacement Program APRIL 2014.docm
CPJ April 2014
http://WPG-APPS-369/PROD/CopperLeaf5/docs/4298 Gen S Roof Replacement Program Addendum March 2014.docm
CPJ March 2014
http://hrcs.hydro.mb.ca/its/aip/Documents/Draft/4298 Gen S Roof Replacement 2013-14 CPJ.docm
cpj
http://hrcs.hydro.mb.ca/its/aip/Documents/Draft/4298 Gen S Roof Repl CPJ 13-14.docm
2013/14 CPJ
http://WPG-APPS-369/PROD/CopperLeaf5/docs/2/CPJ_GEN S ROOF REPLACEMENT PROGRAM.docm

http://WPG-APPS-369/PROD/CopperLeaf5/docs/Draft CER.pdf

http://WPG-APPS-369/PROD/CopperLeaf5/docs/Slave Falls GS Roof Ratings.pdf

http://WPG-APPS-369/PROD/CopperLeaf5/docs/Manitoba Hydro Roof Rating Guide.pdf

http://WPG-APPS-369/PROD/CopperLeaf5/docs/Jenpeg GS Roof Ratings.pdf

CAPITAL PROJECT JUSTIFICATION FOR

KETTLE GS PETROLEUM STORAGE FACILITY

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division: John Koenel P.Eng 2014 02 27

Financial Department:
(if over $1 million) 2014-02-27

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

FOR F. MACINNES.
Business Unit V.P.: 2014-03-02.

BUDGET $: (Total Net Cost)	$5,043,000
START DATE: (1st Cost Flow)	2014 04
IN-SERVICE DATE: (Last Major In-service Date)	2014 12
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: Generation North

I.M. NODE NUMBER: 1.1.1.3.14.1

W.B.S. NUMBERs: ~~P:21919~~ P:16830

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Allan Desserre, P.Eng.

DATE PREPARED: 2013 11 25

REPORT NUMBER: 4554

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☒ Environmental

NERC COMPLIANCE*: ☐ **YES** ☒ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Kettle GS Petroleum Storage Facility

Recommendation

Approve a core capital budget of $5.0M to salvage existing components and construct a new petroleum storage facility inside the Kettle GS to replace original storage tanks that have become non-compliant with Manitoba Regulation M.R. 188/2001 before December 31, 2015.

Risk of not proceeding could extend a unit outage by 37+ days due to oil delivery timeframes.

Project Scope

Scope includes:

- Design, purchase, and installation of API compliant storage tanks
- Decommissioning, destruction and removal of non-compliant tanks
- Piping system replacement and new oil pumping system
- Temporary storage of turbine lubricating oil by site
- Lighting upgrades to the oil storage room
- Transfer point spill containment
- Electrical supply upgrades to oil storage system components

Item	Amount (in millions)
Removal, Supply & Install	$2.9
Engineering / Design	$0.8
Contingency	$0.8
Interest / Escalation	$0.3
Project Management	$0.2
TOTAL	$5.0

Background

The project is currently funded from domestic capital P:16830 with a budget of $1.6 million and actuals to date of $714,000.

The actuals to date reflect the majority of engineering/design that has been completed under the domestic budget and are included in this CPJ estimate. With approval of this CPJ the domestic project costs will be transferred to this project and the domestic project will be cancelled.

The required increase in budget is due to higher than estimated construction costs realized when the first RFQ came in well over budget. The first RFQ was cancelled, the technical specifications reviewed, a new estimate created to reflect market pricing and the contractor's scope reduced. As well, the engineering costs have increased due to changes to the technical specification.

The tanks store new and filtered turbine lubricating oil and headgate hoist hydraulic oil that are vital to the operation of the generating equipment.

Background
Site requires the following oil storage volumes: • 35 000 litres of new turbine lubricating oil to maintain the current inventory for refilling one complete hydraulic generator, • 30 000 litres of filtered turbine lubricating oil, • 6 000 litres of new hydraulic oil to maintain the current inventory for the headgate hoists, and • 6 000 litres of filtered hydraulic headgate hoist oil. As well, the ability to transfer oil to and from the oil storage room through piping systems reduces the risk of spills dramatically rather than using portable totes and pumps. The use of portable totes or barrels was considered but ruled out by all parties involved due to fire code concerns, oil containment, and increased risk of spills due to increased handling.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
The existing tanks do not meet current compliance requirements and cannot be upgraded to satisfy Manitoba Regulatory requirements of M.R. 188/2001. The original permit was to expire in 2005, but we requested and received two five year extensions (2005 and 2010) and were advised to not ask again. System Reliability - Kettle GS is the largest user of turbine lubricating oil of all generating stations at MH. Without on site storage of new and filtered used turbine lubricating oil, a unit outage could be extended by 37+ days due to oil delivery timeframes. The original tanks will lose their certification on Dec 31, 2015 as Manitoba Conservation will not allow us to continue using tanks that do not have appropriate certification to today's regulation.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.4%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Replace existing petroleum storage tanks with compliant with M.R. 188/2001	($4,797,745)

Other Alternatives Considered	NPV Benefits/(Costs)
Decommission existing tanks only - Risks include removal costs and extended outage time of 37+ days for oil shipment for equipment maintenance. Not recommended.	
Do Nothing - Risk non-compliance with M.R. 188/2001. Unacceptable option. Not recommended.	

Risk Analysis

The new tanks are an operational requirement.

A medium risk that oil transfers and oil storage to allow for the salvage and installation to occur in the oil room will need to be done by an external contractor (increased costs and schedule delays). We have mitigated this by getting site management agreement to do this work.

A low risk that contractors will refuse to bid on the work or will bid higher prices since we cancelled the first RFQ. We will mitigate this risk by sending an email to original bidders to explain why we cancelled and how we have changed the scope and reduced the contractor's risk.

The work at Kettle for installation is being scheduled to avoid the stator rewind work planned for start in February 2015.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	618
2013/14	$	214
2014/15	$	4,210
2015/16	$	-
2016/17+	$	-
Total	$	5,043

Proposed Schedule

Engineering design – complete 2013 11
Supply and install contract – awarded 2014 02
Installation at site starts – 2014 09
ISD - December 31, 2014 (before stator rewind work begins)

Related Projects

P:16830 Domestic Project - Kettle GS Petroleum Storage Facility

Reference Documents

CAPITAL PROJECT JUSTIFICATION FOR

Brandon Victoria Ave. Station 115kV Circuit Breaker Replacements

REVIEWED BY:
(Owning Dept Manager) DAVID SWATEK 2014/06/02

NOTED BY:
(if applicable)

Coordinating Division: 2014.06.11

Constructing Division:

Designing Division:

Financial: 2014.06.11

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 11 06 14

Business Unit V.P.: 14 06 11

BUDGET $: (Total Net Cost)	$4,226,000
START DATE: (1st Cost Flow)	2016 04
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	Mult - 2019 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (980 points)
INVESTMENT REASONS:	Employee Safety (80%) Equipment Protection (20%)

OWNING DIVISION: Transmission Planning & Design

I.M. NODE NUMBER: 1.1.2.3.56.1

W.B.S. NUMBERS: P:21768

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: M.R. Wonsiak, Project Owner MRW 2014-05
T.P. Akhi, Project Manager TPA 2014/05

DATE PREPARED: 2014 03 11

REPORT NUMBER: SPD 2012/13

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☒ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE * ☐ **YES** ☒ **NO**

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Brandon Victoria Ave Station 115kV Circuit Breaker Replacements

Recommendation

Replace nine 115kV circuit breakers at Brandon Victoria Station at a total cost of $4,226,000 for a staged in-service from November 2017 to October 2019.

Project Scope

At Brandon Victoria Station:

- Salvage nine 115kV BRBO type FS5C.1 circuit breakers (B5, B6, BE1, BE2, Bus Tie, EH13, MR11, R11, and R23) and associated external current transformers.
- Install new 115kV, 2000A, 40kA dead tank type circuit breakers; utilize internal current transformers for protection and metering.

Background

The available short circuit level of Manitoba Hydro's transmission and sub-transmission system continues to grow as each generation and transmission facility is added. To ensure that circuit breakers maintain the ability to safely interrupt increasing short circuit currents, regular assessment studies are conducted that recommend the replacement of under-rated breakers at a fault level of approximately 95% of their individual Maximum Symmetrical Interrupting Rating (MSIR).

System Planning report SPD 2012/13 documents the systematic approach used to evaluate all 115kV, 66kV, and 33kV circuit breakers at the Brandon Victoria Ave station (circa 1950) in Brandon, Manitoba. The report concluded that nine 115kV circuit breakers are currently above or near 95% of their MSIR and therefore require replacement. The report recommended an in-service of June 2016; however, some of the key resource areas needed on this project are already fully committed on other higher-priority projects over the next several years, such that the start date for this project has been assumed to occur no earlier than fiscal 2016/17. In addition, outage restrictions will allow for only three breakers to be replaced at a time. Based on a start of April 2016, ten months to specify and manufacture the breakers, and six months for installation and commissioning, and given the outage restrictions, the earliest possible in-service date for the first set of breakers is November 2017, while the final set will be completed by October 2019.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

A catastrophic failure of a circuit breaker from fault currents that exceed its interrupting capability can result in serious or fatal injuries to employees and/or the public. In addition to safety concerns, there is a potential risk that equipment located adjacent to an under-rated circuit breaker could also become damaged, increasing equipment replacement costs and outage times. Replacement of under-rated breakers at a fault level of approximately 95% of their MSIR is a prudent and conservative approach to ensuring the safe and reliable operation of the power system while providing enough lead time to accommodate equipment procurement, design and installation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Deferral of these replacements will increase the risk of catastrophic failure, as once Bipole III is in service the fault levels at Brandon Victoria Ave will increase by 1-2%.

Alternatives that were considered for permanently reducing 115kV fault levels at Brandon Victoria Ave Station were to decouple the 115kV network or to add current limiting reactors; however, neither is recommended. Decoupling or splitting the 115kV network would result in a reduction in system reliability as well as the ability to serve load. Current limiting reactors used as a means of achieving a reduction in fault levels will increase the reactive power requirements of the transmission system. In addition, the increased DC offset (X/R ratio) may saturate current transformer cores and affect the performance of relay protection schemes.

Capital Investment Categorization:
See link for instructions: http://t.hydro.mb.ca/tclm/tp/Capital%20Project%20Justification%20CPJ/Capital%20Investment%20Categorization.doc

Driver	Category	Sub-category	Split	Amount
Safety	Employee Safety	Asset Improvement	80%	$3,381,000
Reliability–Outage Related	Equipment Protection	Asset Improvement	20%	$ 845,000
				$4,226,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	5.4%	For current corporate rates see G911 For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Replace nine 115kV circuit breakers and associated current transformers for a staged in-service from November 2017 to October 2019.	($3,004,000)

Other Alternatives Considered	NPV Benefits (Costs)
Decouple/split the 115kV network. This alternative is not recommended as it would result in a reduction to system reliability and the ability to serve load.	Not Estimated
Add current-limiting reactors. This alternative is not recommended as it would increase the reactive power requirements of the transmission system, and affect the performance of the relay protection schemes.	Not Estimated

Project Risk Analysis

A total contingency of $499,000 (15% of the base) has been included in the estimate for potential changes in the scope of work or design, material cost increases, outage delays, unfavourable weather conditions, need for winter construction, and unavailability of labour resources. The breakdown of contingency by area is as follows:

- $195,000 for Electrical Construction
- $148,000 for Station Design-ACE
- $90,000 for Civil Construction
- $66,000 for various other areas.

It should be noted that the project plan is based on delivery of three breakers per year over three years, either through special arrangements on a single purchase order, or by issuing a separate purchase order for each set of three breakers. This may result in different suppliers and/or changes to model numbers and internal design, which could necessitate additional work by Station Design-ACE. The alternative is to issue a single purchase order for delivery of all nine breakers in 2016/17, which would increase that year's budget requirements by approximately $576,000 plus additional capitalized interest thereafter, as well as introduce challenges with storage and warranty.

Capital Budget Estimate

The annual and total net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	–
2014/15	$	–
2015/16	$	–
2016/17	$	1,092
2017/18	$	1,067
2018/19	$	1,031
2019/20	$	985
2020/21	$	52
Total	$	4,226

Proposed Schedule

Project Activity	Date
Project kick-off	April 2016
Completion of Protection Report	June 2016
Delivery of breakers (three per year)	February of 2017, 2018 and 2019
Issue of design and drawings	June 2016 - March 2017
Salvage and installation of 1st set of 3 breakers	May 2017 - Nov 2017
Salvage and installation of 2nd set of 3 breakers	May 2018 - Nov 2018
Salvage and installation of 3rd set of 3 breakers	May 2019 - Oct 2019

Related Projects
None.

Reference Documents
System Planning Department report *Brandon Victoria Ave Station 115kV Circuit Breaker Replacements SPD 2012/13* dated 2013 04 22.

CAPITAL PROJECT JUSTIFICATION FOR

Bipole I&II Failed Anchor Replacement

REVIEWED BY:
(Owning Dept Manager) 11/14/14

NOTED BY:
(if applicable)

Coordinating Division: 11/14/14

Constructing Division: 2014/11/14

Designing Division:

Financial: Quenenburg 2014.12.01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/12/01

Business Unit V.P.: A. Bailey Dec 1, 2014

BUDGET $: (Total Net Cost)	$3,500,000
START DATE: (1st Cost Flow)	2014 11
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	2015 03
RISK MATRIX/ BUSINESS CASE TIER:	Mandatory (scored at 1690 points)
INVESTMENT REASONS:	System Emergencies (90%) Employee Safety (5%) Public Safety (5%)

OWNING DIVISION: TRANS CONTRUCTION & LINE MAINTENANCE

I.M. NODE NUMBER: 1.1.2.3.66.1

W.B.S. NUMBERS: P:24073

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J. Schmidt on behalf of
D. Day, Project Owner
J. Peterson, Project Manager

DATE PREPARED: 2014 11 06

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☒ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE * ☐ **YES** ☒ **NO**

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Bipole I&II Failed Anchor Replacement

Recommendation

Replace ten failed anchors on Bipole I&II and one failed anchor on 138kV transmission line KN36 (Kelsey to Radisson). The total net cost is estimated at $3.5 million for an in-service of March 2015.

Project Scope

Tender a Request for Proposal for the design, supply and installation of vertical micropiles to repair failed anchors at ten structure locations on Bipole I&II and one structure location on KN36.

Preliminary designs have been completed by Manitoba Hydro engineers and will be submitted to the bidding contractors for consideration. Final designs will be completed by the contractor based on their specialized equipment and methodology. Access to site will require winter roads and/or helicopter support.

Work is to be completed at the following tower locations as shown on the attached map:

- L2-288-A4
- L2-301-A3
- L2-379-A1
- L2-379-A2
- L1-381-A4
- L1-382-A3
- L1-399-A3
- L2-399-A3
- L2-513-A2
- L1-517-A4
- KN36-62

Background

Record flows on the Nelson River prior to the winter of 2011/12 resulted in water as deep as fifteen feet within the Bipole I&II right-of-way along Cauchon Lake and Sipiwesk Lake, approximately 85km southeast of Thompson. Several tower anchors and footings were frozen into the ice during the ensuing winter, and water level fluctuations throughout the winter caused damage to and ultimately failure of ten anchors on Bipole I&II. Temporary anchors were installed on these ten structures under emergency conditions during that winter, to prevent the immediate collapse of the associated towers.

The failed anchor on KN36 is due to long-term degradation of the permafrost.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The temporary anchors that were installed were not designed to be a permanent solution and must be replaced regardless of whether there is a recurrence of flooding and ice build-up. Inspections of the

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

affected structures have found movement of the cement blocks that were placed as temporary anchors resulting in slack guys. The present situation puts Bipole I&II at a high risk for tower failure, either during a weather event or a cascading failure. In addition, maintenance work such as the approved project for spacer damper replacements can't be safely completed on the towers that have the temporary guy anchors.

Given the close proximity of the failed anchor on KN36 to the proposed anchor replacement work on Bipole I and II, and given the importance of line KN36 in supplying construction power for the Keewatinohk Converter Station and the Keeyask Generating Station, it is recommended the KN36 anchor be replaced as part of this project.

The proposed design solution will resist loads imparted by ice forming around the anchor while minimizing access requirements for implementation. Consideration of access requirements as part of the design was essential given the difficulty experienced when making emergency repairs to the failed anchors. Access to the flooded area was extremely challenging and required a winter road plus improvements to the existing Clearwater Bridge to allow for heavy equipment to be brought in. Although the bridge has been brought up to original ratings, it still has weight and width restrictions which limit the equipment that can be transported over the bridge. The innovative design solution can utilize equipment that can be transported by helicopter or with light duty vehicles, minimizing access road requirements. Vertical micropiles have been used by SaskPower and BC Hydro, but never before by Manitoba Hydro.

There were three other alternatives considered:
a) replace the existing anchors with the original design;
b) same as a), but also mound granular materials to create an island around the anchor; and,
c) leave the temporary anchors in place.

Option a) is not recommended as the original design has proven to be ineffective against the ice build-up that's occurring in the area. Option b) was rejected on the basis that suitable granular material is not available locally, which would have necessitated building roads to haul material in from elsewhere, at a substantial cost. Option c) is not acceptable as the temporary anchors develop only 35% of the required resistance that's needed to maintain the reliability of the line.

It is highly recommended that this work take place as soon as possible. High water levels have left the ground saturated and flood conditions are lasting longer and becoming more common. It is not known how long the temporary anchors will last under these conditions. A further consideration is the need to gain some experience with installation and performance of the new design in order to arrive at a proven, cost effective solution for anchoring towers that have continued exposure to flooding and ice movement. It is anticipated that other sections of the lines will see similar conditions and may require remedial work, compounding the risk of structure failures on the Bipole I&II lines.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability-outage related	System Emergencies	Weather/storm	90%	$3,150,000
Safety	Employee Safety	Asset Sustainment	5%	$ 175,000
Safety	Public Safety	Asset Sustainment	5%	$ 175,000
				$3,500,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	4.75%	For current corporate rates see G911 For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Replace failed anchors. Positive NPV is based on the cost of the project being offset by avoidance of just one outage event caused by a failed structure or structures with the subsequent repairs taking approx. five days to complete and revenue losses assumed to be $1M/day.	$1,342,000

Other Alternatives Considered	NPV Benefits (Costs)
Replace the existing anchors with the original design.	Not available
Replace the existing anchors with the original design and mound granular materials to create an island around the anchor.	Not available
Leave the temporary anchors in place.	Not available

Project Risk Analysis
A Contingency of $300,000 or 10% has been included to cover the risk of water levels affecting access during construction. This could lead to additional costs such as expenditures sunk into a winter road which becomes unusable, the requirement for additional helicopter support, and/or the inability to complete the work in one construction season. The purchase order for the construction contract must be placed by December 17 to achieve a January 2015 start in order to ensure a March 2015 completion.

Capital Budget Estimate

The annual and total net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2014/15	$	3,468
2015/16	$	32
2016/17	$	-
Total	$	3,500

Proposed Schedule

Activity	Dates
Issue RFQ	November 19, 2014
Award Purchase Order	December 17, 2014
Construction	January – March 2015

Related Projects

- BPI&II Footing Extensions (1.1.2.25.6.3-P16916-G1, completed January to March 2012).
- BPI&II Access Improvements - Clearwater Bridge (1.1.2.25.1.50- P:20954, completed December 2012 – August 2013)
- Bipole I&II Spacer Damper Replacements (1.1.2.3.61.1, to go in-service in stages from June 2015 to November 2016)

Reference Documents

Map of structure locations and recent photos of temporary anchors.

CAPITAL PROJECT JUSTIFICATION FOR

Anola DSC RM of Springfield

REVIEWED BY:
(Owning Dept Manager)
KBraid 2014-09-18

NOTED BY:
(if applicable) 2014-09-18

Coordinating Division: 2014-09-18

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 09 18

Business Unit V.P.: 2014-10-07

BUDGET $: (Total Net Cost)	$4,000,000
START DATE: (1st Cost Flow)	2013 07
IN-SERVICE DATE: (Last Major In-service Date)	2015 07 30

OWNING DIVISION: G13800 / Distribution E&C Winnipeg

I.M. NODE NUMBER: 1.1.3.6.51.1

W.B.S. NUMBERs: P:21933

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Harinder Sawhney 18/9/2014

DATE PREPARED: 2014 04 08

REPORT NUMBER: DEW-W14-03

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☐ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Anola DSC RM of Springfield

Recommendation

Construct a new 115-12.47 kV, 10 MVA DSC site adjacent to Manitoba Hydro's 115 kV line ST6 R.O.W at SW10-11-6E near the town of Anola for an ISD of 2015 07 30. The DSC site will be comprised of a 10 MVA high voltage padmount transformer (HVPT), recloser and associated equipment. The cost is estimated at $4.0M.

Project Scope

The recommended scope, which forms the basis for the budget and schedule contained herein, is for the following:

Construct a new 115-12.47 kV 10 MVA DSC on 115 kV line ST6 right of way at SW10-11-6E. The DSC site will be comprised of:

- Two new 12.47 kV feeders AL12-1 and AL12-2(Reconductoring of certain portion of feeders up to 15 km in length is required to improve voltage regulation in the area and connect feeders OB12-8 and DD12-3. Details are given in the Planning report)
- 3-115 kV gang operated switches,
- 3-12.47kV, 548 A padmount regulators,
- 1-15kV, 4-way automated switching cubicle,
- 1-50kVA single phase padmount transformer,
- metering cabinet and digital metering.

Install a second set of cooling fans on the existing transformer banks at Oakbank Station.

Background

Dugald and Oakbank Stations currently supply load in the area of the communities of Dugald, Anola and Oakbank. Oakbank Station is the main supply station for the Oakbank area. The station consists of two-115/12.48 kV transformers rated at 10/13.3 MVA and 7.5/10 MVA. The station firm capacity is 10.8 MVA and winter station capacity limit (normal loading limit with both banks in service) is 24 MVA. Station loading in winter is 22.9 MVA which is 212% of winter firm capacity and close to the total normal station capacity limit. Oakbank Station has some internal feeder ties and some external feeder ties to Dugald Station. These ties are reaching their loading limits as new development continues in the area.

Dugald Station consists of two-66/12.47 kV transformers. The firm limit of Dugald Station is 6.48 MVA in winter and station loading is presently 12.56 MVA in winter (194% of station winter firm limit). Dugald Station has feeder ties with Oakbank, Vivian and Lorette Stations. Only one external feeder tie is valid for Dugald Station and very few internal feeder ties can pick up load in case of an outage. Although external feeder tie capacity is available, there is no capacity remaining at the receiving stations during winter peak condition.

Any load in excess of station firm capacity needs to be transferred to adjacent stations via feeder ties or customers will experience lengthy outages. As all capacity at Oakbank and Dugald Stations has been

Background

exhausted, there is high potential of extended customer outages during winter conditions. Additionally, load is growing due to development of the Dugald and Oakbank areas. Table 1 below summarizes the loading for Oakbank and Dugald Station.

Table 1. Summary of Oakbank and Dugald Station

Station	Winter Firm (MVA)	Winter Load (MVA)	Loading (% of Firm)
Oakbank	10.8	22.9	212
Dugald	6.48	12.6	194

Justification

Table 1 shows current capacity at Oakbank and Dugald station is not sufficient to supply increasing load in the area due to new development. Residential development in Oakbank and Dugald area is growing and is expected to continue as developers construct new houses in the area. Dugald station loading has grown at 3.7% in past ten years. Oakbank Station growth has been more significant at 4.5%. Both stations are winter peaking. The additional capacity will provide area firm capacity and accommodate future load growth in the Dugald, Oakbank and Anola communities. A 10 MVA HVPT with over loading capacity of 125% in normal winter condition will provide a capacity gain of 12.5MVA. New feeders AL12-1 and AL12-2 will pick up load from Oakbank feeder OB12-8 and Dugald feeder DD12-3 resulting in total load transfer of 11 MVA to Anola DSC as shown in Table 2. The Anola DSC is the first stage of reducing loading at Dugald and Oakbank Stations below firm capacity. The second stage of the project is to be justified in a separate CPJ includes installing a 10 MVA 115-12.47 kV DSC on 115 kV line ST5 right of way at NE09-11-5E.

Oakbank Station Bank 1 is rated for 10/13.3 55^{o} C ONS(Oil Natural Static)/ONP(Oil Natural Pumped) with single stage fans. As the new DSC site cannot be constructed in time for the 2015 winter loading, additional transformer fans are required to provide cooling and 3 MVA of additional capacity during heavy winter station loading

Table 2. Station Loading

Station	Current Load [MVA]	Proposed Load [MVA]	Station Firm [MVA]
Dugald (2-3.75/5 MVA)	12.56 (97%)	7.56 (58%)	6.48
Oakbank (1-10,1-13.3 MVA)	22.87 (94%)	16.87 (69%)	13.8*
Anola (1-10 MVA)	-	11 (78%)	0
Total	35.43	35.43	

Note: percentages are load percent of normal station capacity limit.

**includes additional cooling fans*

.

This project is required to ensure that the Oakbank and Dugald area has reliable service. This project will ensure to meet Customer Service and Distribution business goal that is to "Provide Exceptional Customer value" by being prepared for the new load and future customer connection requests : as well as "Develop and deliver sustainable energy distribution systems for future generations" by ensuring firm capacity of the

Justification

supply system.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Rel. – Load-Related (F7)	Cap. Enhancement (FD)	New Asset Addition (HN)	100%	$4,000,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	5.30%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Anola DSC Install a new 115-12.47 kV, 10 MVA DSC site on Manitoba Hydro 115 kV line ST6 R.O.W at NE09-11-6E near Anola for an ISD of 2015 07 30. The DSC site will comprise of a 10 MVA high voltage padmount transformer (HVPT), recloser and associated equipment. There is land available for a 2nd HVPT for future load growth.	($3,905,000)

Other Alternatives Considered	NPV Benefits/(Costs)
Add Transformer Banks at Oakbank and Dugald Stations This alternative is not recommended as adding an extra bank at Oakbank Station is not possible due to space limitations on the existing station site. Adding an extra bank is not feasible at Dugald Station as the 66 kV supplying the station is overloaded.	N/A

Risk Analysis

There is a risk of construction resources assigned to other high priority projects that could impact in-service date.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	35
2014/15	$	2,082
2015/16+	$	1,883
Total	$	4,000

Proposed Schedule

December 2014: Design Completed
May 2015: Civil Construction Completed
July 2015: Complete DSC Installations including commissioning and system functional testing.

Related Projects

None

Reference Documents

Dugald/Oakbank Area Capacity Study "DEW-W14-03"

CAPITAL PROJECT JUSTIFICATION FOR

Winkler West DSC

REVIEWED BY:
(Owning Dept Manager) Glenn R Penner 20140117

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 20140221

Business Unit V.P.: 2014-02-25

BUDGET $: (Total Net Cost)	$4,550,000
START DATE: (1st Cost Flow)	2012 06
IN-SERVICE DATE: (Last Major In-service Date)	2014 11

OWNING DIVISION: G13700 / Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.8.26.1

W.B.S. NUMBERs: P:19794

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Rodney Boychuk RB 2014/01/17

DATE PREPARED: 2014 01 08

REPORT NUMBER: 7892

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☒ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Winkler West DSC

Recommendation

Installation of a Distribution Supply Centre (DSC) and transfer approximately 11MVA of load from Winkler North station. Includes 66kV line extension and feeder construction.

Project Scope

2 - 10MVA 66-12.47/7.2kV High Voltage Padmounts
2 - 66kV Underground Transition Structures c/w fusing
2 - 66kV Vac-rupter Switches
1 - 66kV Non-Load Break Switch
6 - Padmount Regulators
2 - Switching Cubicles
4 - Padmount Reclosers
Future Communication Provisions
Property Purchase
Extension of 66kV Line
Construction of Feeders, 8kV Feeder Conversion, Interchange Bank Installation

Background

There is a large amount of load growth occurring in the northwest corner of Winkler and the area west. Winkler North Station is the only supply for this area and the load has exceeded the station's firm operating limits. Based on a historical load growth of 6.1% the station banks are further expected to be overloaded within the next two years.

Winkler North station is located at the north end of the city and presently has five 12.47kV feeders. The west portion of the city is supplied by three of the 12.47kV feeders and they all presently exceed our planning criteria of 5MVA per feeder. This is affecting load transfer capabilities and service continuity in the city.

Existing station configuration and location limits the possibility of creating additional feeders to supply this area. A solution to provide increased capacity and service reliability is required in order to meet the requirements of our Urban Planning Standard.

Justification

The DSC site will supply approximately 11MVA of load currently supplied by Winkler North station. The site will be located two kilometers west of Winkler and would remove load from Winkler North feeders WR12-3, WR12-4, and WR12-7.

Based on historical load growth, the new DSC site would provide station and feeder capacity for fifteen years. This option will create a source located near areas identified for residential expansion and will provide viable feeder ties with Winkler North and Winkler Market stations creating area firm capacity as required by the Urban Planning Standard. The installation of the DSC will also free capacity at Winkler North station and increase its ability to supply future load increases north of Winkler.

Justification
Without remediation, Winkler North Station load will exceed its capacity within by winter 2014/15; the bank loading will exceed acceptable limits.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability - Load Related	Capacity Enhancement	New Asset Addition	100%	$ 4,550,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
Installation of a Distribution Supply Centre (DSC) and transfer approximately 11MVA of load from Winkler North station. Includes 66kV line extension and feeder construction.	-$4,322,000

Other Alternatives Considered	**NPV Benefits/(Costs)**
Expand Winkler North station and install a third transformer The existing station would be expanded and a new 15MVA, 66-12.47kV transformer installed to supply four feeder positions. Due to the location of the station, the new feeders would need to be built through the city's core or at length around the perimeter to supply future growth and remove load from existing feeders. The number of viable feeder ties would be limited which prevents the possibility of area firm capacity.	-$4,749,000

Risk Analysis
There are no unusual risks associated with completing this project as recommended.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	37
2013/14	$	57
2014/15	$	4,456
2015/16+	$	-
Total	$	4,550

Proposed Schedule

Engineering: March – August 2014
Order Material: March – August 2014
Construction: October - November 2014
ISD: November 30, 2014

Related Projects

None

Reference Documents

Planning Study No DER-S13-04 *Winkler West DSC*

CAPITAL PROJECT JUSTIFICATION FOR

Norway House Bank Addition

REVIEWED BY:
(Owning Dept Manager) 2014 03 07

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014 03 19

Business Unit V.P.: 2014 03 20

BUDGET $: (Total Net Cost)	$4,000,000
START DATE: (1st Cost Flow)	2015 01
IN-SERVICE DATE: (Last Major In-service Date)	June 2016

OWNING DIVISION: G13700 / Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.8.27.1

W.B.S. NUMBERs: P:22935

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Boychuk, Rodney RB 2014/03/07

DATE PREPARED: 2014 02 05

REPORT NUMBER: 9264

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☒ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Norway House Bank Addition

Recommendation
Installation of a new 66-12.47kV, 9/12/15MVA transformer at Norway House Station with a targeted in-service date of June 30, 2016.

Project Scope
Install a new 66-12.47kV, 9/12/15MVA transformer and associated equipment at Norway House Station.

Background

The community of Norway House is a remote island community with a population of approximately 4500 people. It is located on the north-east side of Lake Winnipeg and is accessible only by ice road during the winter months and a ferry during the rest of the year. Due to the challenges related to accessing the community, Norway House requires firm capacity in order to ensure extended outages do not occur.

Presently, the community is supplied by two sources, Norway House Station and Norway House School DSC. Norway House Station firm capacity is 14.4MVA; peak loading is 16.5MVA. Norway House School DSC firm capacity is 6.6MVA; peak loading is 2.6MVA. The lack of station firm capacity at Norway House Station means that in the event of a 1st contingency failure we would rely on area firm capacity to supply the community. This would require feeder NH12-4 (presently 4.2MVA) be transferred onto the Norway House School DSC and the two high-voltage banks be tied in parallel in order to accommodate the additional load.

Justification

The lack of station firm capacity at Norway House Station means that in the event of a 1st contingency failure we would rely on area firm capacity to supply the community.

Based on the 10 year historical growth rate of 2.5% Norway House area firm capacity will be exceeded in fall 2016. At that time, a first contingency failure will result in loading equipment beyond planning limits, resulting in forcing rolling outages until load subsides or the failed equipment can be replaced/repaired. Because of the remote nature of this site, equipment replacement could require multiple months.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability - Load Related	Capacity Enhancement	New Asset Addition	100%	$ 4,000,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Installation of a new 66-12.47kV, 9/12/15MVA transformer at Norway House Station; in-service date of June 30, 2016.	-$3,559,000

Other Alternatives Considered	NPV Benefits/(Costs)
Install a new DSC site consisting of a two 10 MVA, 66-12.47 high voltage padmount transformers to supply approximately 7.5MVA of load currently supplied by Norway House Station.	-$5,295,000

Risk Analysis

There are no unusual risks associated with completing this project as recommended.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2014/15	$ 100,000
2015/16	$ 2,900,000
2016/17+	$ 1,000,000
Total	$ 4,000,000

Proposed Schedule

Engineering: January - December 2015
Order Material: October 2014 – December 2015
Haulage: February – March 2016
Construction: May – June 2016
ISD: June 30, 2016

Related Projects

None

Reference Documents

Planning Study No DER-S13-03 *Norway House Firm Capacity*

CAPITAL PROJECT JUSTIFICATION
FOR

Ste Agathe Stn Bank Addition

REVIEWED BY:
(Owning Dept Manager)
Glenn Parkhurst 20140512

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:
Charles Steele 2014 05 15

Business Unit V.P.:
Brent Reid 2014 06 05

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ YES ☒ NO

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

BUDGET $: (Total Net Cost)	$2,100,000
START DATE: (1st Cost Flow)	2016 01
IN-SERVICE DATE: (Last Major In-service Date)	2016 09 30

OWNING DIVISION:	G13700 / Distribution E&C Rural
I.M. NODE NUMBER:	1.1.3.8.28.1
W.B.S. NUMBERs:	P:20766
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Rodney Boychuk
DATE PREPARED:	2014 04 08
REPORT NUMBER:	9076
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Ste Agathe Stn Bank Addition

Recommendation
Install a new 66-12.47kV, 9/12/15MVA transformer and replace existing hydraulic ACR's with electronic.

Project Scope
Install a new 66-12.47kV, 9/12/15MVA transformer at Ste. Agathe station in the vacant Bank 2 bay.
Install four new three phase electronic ACR's.
Maintain existing Bank 1 as an ice melt bank.

Background
Ste. Agathe Station is a steel station with an existing 66-12.47kV, 3.75/5MVA transformer (Bank 1) that supplies three feeders. The station is commonly used for ice melting with the existing Bank 1 designated as an ice melt bank. During ice melt conditions, tie points are used to transfer load to neighbouring stations and limit the number of customer outages. Due to increased loading in the area, this is no longer possible.

Justification
Ste. Agathe Station has experienced a ten year average historical load growth rate of approximately 4% per year and will exceed the station's loading limit of 6.8MVA by fall 2017. The station requires an increase in available capacity.

The recommended option is to install a new 66-12.47kV, 9/12/15MVA transformer in the vacant Bank 2 position and leave the existing Bank 1 in place as an ice melt bank. Loading issues on Bank 1 will be eliminated by transferring load to the new bank. The feeder ACR's will also be replaced at this time to accommodate load growth and provide station metering. Historic annual load growth shows that this capacity increase will allow us to meet the areas load requirements for the next 15 years based on an anticipated in service date of 2016-09-30

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Install a new 66-12.47kV, 9/12/15MVA transformer c/w required electrical and civil work associated with the addition; replace existing ACR's with electronic.	($1,920,000)

Other Alternatives Considered	NPV Benefits/(Costs)
Install a new 66-12.47kV, 10 MVA DSC site. This would require maintaining the existing station for ice melting.	($2,260,000)

Risk Analysis

There are no unusual risks associated with this work.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2014/15	$ 250,000
2015/16	$ 100,000
2016/17	$ 1,750,000
Total	$ 2,100,000

Proposed Schedule

Install ACR's: July – September 2014
Order Bank: September 2014
Engineering: January – July 2016
Procure Material: July 2016
Construction: August - November 2016

Related Projects

None

Reference Documents

Study No: DER-S12-09 Ste. Agathe Station Bank Addition
Capital Budget Single Line Diagram Ste Agathe Station Bank Addition

CAPITAL PROJECT JUSTIFICATION FOR

Hochfeld DSC

REVIEWED BY:
(Owning Dept Manager) 2014 04 08

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Charles Steele 2014 05 05

Business Unit V.P.: Brent Read 2014-05-16

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☒ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

BUDGET $: (Total Net Cost)	$5,000,000
START DATE: (1st Cost Flow)	May 2013
IN-SERVICE DATE: (Last Major In-service Date)	August 2015

OWNING DIVISION: G13700 / Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.8.25.1

W.B.S. NUMBERs: P:21652

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Boychuk, Rodney 2014/04/0

DATE PREPARED: 2014 03 07

REPORT NUMBER: 8523

FILE NUMBER (Optional):

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Hochfeld DSC

Recommendation

Install a new DSC site with two 10MVA, 66-24.9kV high voltage padmount transformers, 6.5 km of 66kV line, and four feeder positions approximately eight kilometers south of Winkler. Targeted in-service date is August 30, 2015.

Project Scope

Install a new DSC site with two 10MVA, 66-24.9kV high voltage padmount transformers (P:21652), 6.5 km of 66kV line (P:21654), and four feeder positions to supply approximately 12MVA of load (P:21653) currently supplied by Winkler Market and Plum Coulee stations.

Background

Present area issues are as follows:

- Winkler Market Bank 4 is expected to exceed normal bank capacity in 2017/18. It normally supplies only Feeder WM25-13.
- Feeder WM25-13 extends for over 24km and supplies over 12MVA of load.
- Plum Coulee feeder PC25-6 extends for over 32km and supplies 6MVA of load.
- Hochfeld area loading is approximately 12MVA, with annual load growth averaging 5%. The area is experiencing voltage problems and reliability issues due to the long feeders.

Justification

The DSC site would immediately supply approximately 12MVA of load currently supplied by Winkler Market and Plum Coulee Stations. The site would remove load from Feeders WM25-13 (9.0MVA) and PC25-6 (3.0MVA). It will also allow for future conversion of Feeder WR8-4 (1.5MVA), resolving voltage issues.

Based on historical load, the new DSC site would provide station and feeder capacity in the area for a minimum of fifteen years. This option would create a source located near a rural load centre. Viable ties will be available with Winkler Market and Plum Coulee feeders for non-peak periods of the year.

The installation would also free capacity at stations:

- Winkler Market 25kV, increasing its ability to supply City of Winkler load and remaining rural areas south and east of Winkler.
- Plum Coulee that is otherwise predicted to require a bank addition in 2017/18.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability - Load Related	Capacity Enhancement	New Asset Addition	100%	$ 5,000,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
Install a new DSC site with two 10MVA, 66-24.9kV high voltage padmount transformers.	-$5M

Other Alternatives Considered	**NPV Benefits/(Costs)**
Construct a new 66-24.9kV substation south of Winkler and transfer load from Winkler Market and Plum Coulee Stations.	-$7.9M

Risk Analysis

There are no unusual risks associated with this project.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2013/14	$ 20,000
2014/15	$ 80,000
2015/16+	$ 4,900,000
Total	$ 5,000,000

Proposed Schedule

Engineering: May 2013 - May 2015
Order Material: January – May 2015
Construction: May – August 2015
ISD: August 30, 2015

Related Projects

None

Reference Documents

Planning Study No DER-S12-08 *Hochfeld DSC*

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

D1876

CAPITAL PROJECT JUSTIFICATION FOR

Brandon West 4kV - 12kV Conversion

REVIEWED BY: JRC
(Owning Dept Manager) [signature] 20140307

NOTED BY:
(if applicable)
JRC 2014 02 24

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: [signature] 20140318

Business Unit V.P.: [signature] 2014-03-25

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐ Safety ☐ Customer Service
☐ System Supply ☐ Efficiency
☒ System Reliability ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☒ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

BUDGET $: (Total Net Cost)	$4,650,000
START DATE: (1st Cost Flow)	2014 04
IN-SERVICE DATE: (Last Major In-service Date)	2016 12

OWNING DIVISION: G13700 / Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.9.14.1

W.B.S. NUMBERs: P:22894

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Shelvey, Daryn [signature] 2014-02-21

DATE PREPARED: 2014 01 28

REPORT NUMBER: 8872

FILE NUMBER (Optional):

Project Name

Brandon West 4kV - 12kV Conversion

Recommendation

Convert Brandon McTavish and Elviss stations from 4kV to 12kV, transferring the load to Brandon Fortier station. Install 12-4kV interchange bank as a new tie to Brandon University station. Salvage Brandon McTavish and Elviss stations.

Project Scope

This project includes the following:

- Construct new 16 way duct line north from Fortier station to Victoria Ave. and east to 34th St.
- Convert Brandon Elviss station area from 4 to 12kV and serve from Fortier FR12-9
- Install new 2500m 750MCM Fortier feeder FR12-10 in the new duct line from Fortier station to 34th St.
- Convert Brandon McTavish station area from 4 to 12kV and serve from Fortier FR12-10, install a tie to Brandon Lorne station
- Install new 12-4kV 2MVA interchange bank as back up supply for Brandon University station fed from Fortier FR12-10
- Salvage Brandon McTavish and Elviss stations

Background

The 4kV switchgear at Brandon McTavish station is at the end of life with no replacement parts available. The station is within 80% of its firm capacity and cannot accommodate any further load increases due to protection coordination and feeder end voltage issues.

Brandon Elviss and Brandon University stations are both single bank stations which rely on feeder ties to Brandon McTavish for firm capacity. During a contingency, feeder end voltages at Brandon University are below CSA standards.

Justification

Converting Brandon McTavish and Elviss loads from 4 to 12kV will provide capacity for future growth in these station areas and remove two end-of-life stations. Installing a 12-4kV interchange bank at Brandon University will ensure a reliable alternate supply for Brandon University.

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Convert Brandon McTavish and Elviss station areas to 12kV. Includes a new 16 way duct line, new Brandon Fortier feeder FR12-10, 12-4kV padmount transformer at Brandon University, and salvage of Brandon McTavish and Elviss stations.	($4,497,219)

Other Alternatives Considered	NPV Benefits/(Costs)
Replace Brandon McTavish station with a 33-12kV DSC. Convert McTavish and Elviss station areas to 12kV. Install a new 16 way duct line, new Brandon Fortier feeder FR12-10, and a 12-4kV padmount transformer at Brandon University. This alternative does not provide enough capacity for future load growth in the Brandon McTavish and Elviss areas.	($6,669,712)
Replace switchgear at Brandon McTavish station. Convert a portion of the 4kV to 12kV. Install new 16 way duct line and new Brandon Fortier feeder FR12-10. Upgrade tie to Brandon University. This option does not address other issues with Brandon McTavish station and does not provide capacity for future load growth.	($3,892,410)

Risk Analysis

Brandon Fortier has enough capacity to serve this additional load for at least 10 years. There is no risk in proceeding with the recommendations.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	–
2014/15	$	2,000
2015/16	$	2,300
2016/17+	$	350
Total	$	4,650

Proposed Schedule

- New Fortier duct line: 2014-12-31
- Brandon Elviss station conversion: 2014-12-31
- New Brandon Fortier feeder FR12-10: 2015-06-30
- Brandon McTavish station conversion: 2015-12-30
- Brandon University station backup: 2016-06-30
- Salvage Brandon McTavish and Elviss stations: 2016-12-31

Related Projects
None

Reference Documents
Study DER-B13-05: http://WPG-APPS-369/PROD/CopperLeaf5/docs/DER-B13-05.pdf

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

D1876

CAPITAL PROJECT JUSTIFICATION FOR

Glenboro Town 8kV to 25kV Conversion

REVIEWED BY: JAC
(Owning Dept Manager)
2014 05 07

NOTED BY:
(if applicable)

Coordinating Division: JAC

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:
Charles Steel 2014 05 12

Business Unit V.P.:
2014-06-05

BUDGET $: (Total Net Cost)	$2,000,000
START DATE: (1st Cost Flow)	2004 07
IN-SERVICE DATE: (Last Major In-service Date)	2015 10 31

OWNING DIVISION: G13700 / Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.9.15.1

W.B.S. NUMBERs: P:11883

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Shelvey, Daryn 2014-05-05

DATE PREPARED: 2014 04 14

REPORT NUMBER: 8965

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ YES ☒ NO

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

Project Name

Glenboro Town 8kV to 25kV Conversion

Recommendation

Convert the town of Glenboro from 8kV to 24.9kV. The rural feeders will be fed from a step down bank and remain at 8kV until they are deemed end of life. The old 8kV portion of Glenboro North Station will be salvaged.

Project Scope

This project includes the following:

1. Add 3 feeder positions including station ACR's and U/G egresses to the 25kV structure at Glenboro North station. Two positions for town feeders and one position to serve a 3x1000kVA 25kV-8.32kV step down bank feeding 2 - 8kV rural feeders.
2. Install a 4-Way Distribution Center outside Glenboro North station for a tie between GL25-6 & GL25-8.
3. Re-build the 3 x 1000kVA 25kV - 8.32kV step down bank to be fed from the new feeder GL25-8 to serve rural feeder GL08-8(old GL08-1 and GL08-9.)
4. Rebuild 900m of GL25-2 going south of Glenboro North station with 3 x 4/0AL TRXPLE U/G conductor.
5. In the town of Glenboro convert 103 transformer locations from 8kV to 25kV.
6. Replace poles, conductor and hardware as required to meet CSA standards.
7. Install 3 x 100amp 8.32kV voltage regulators on GL08-8 at SW3-7-14W. Salvage 2 x 100amp 8.32kV regulators on GL08-8 at SW24-6-14.
8. Install an underground dip to a 150kVA 3Ø 120/208 Padmount to serve the Glenboro North Station Office fed from GL25-2.
9. Protection Changes for 2 Feeders.
10. Install 1 span 266.8MCM 66kV L74 to splice through in front of Glenboro North station to serve Bank 4 from L74.
11. Salvage the 8kV portion of Glenboro Station.

Background

Glenboro North station is a three bank station (2 x 8kV, 1 x 25kV) supplying the entire area load with 8kV with the exception of one rural feeder which is supplied 25kV. A voltage conversion from 8kV to 25kV began in the 1980s because of minimal station capacity and feeder end voltage problems. A new 66-25kV station structure was built in 1996 to house a 10MVA 66-25kV bank. The long term plan has been to convert the entire station area to 25kV to improve feeder voltages and make use of available 25kV station capacity.

Feeder end voltages on the town and rural 8kV system do not meet CSA minimum limits during peak conditions. The 8kV portion of Glenboro North station has rotted poles and timbers with old and obsolete equipment that has reached end of life.

Justification

The recommendations will eliminate the voltage issues in the Glenboro area and remove the aging 8kV station that has reached end of life.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.05%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Convert the Town of Glenboro from 8kV to 25kV and 8kV station salvage.	(1,903,855)

Other Alternatives Considered	NPV Benefits/(Costs)
Refurbish Glenboro North 8kV.	(2,570,205)

Risk Analysis

Glenboro North 25kV station has enough capacity to supply the area for the foreseeable future. There is a small risk of operational confusion due to combining GL08-1 and GL08-9 into a single 8kV feeder, but protection changes will address this issue.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	–
2015/16	$	2,000
Total	$	2,000

Proposed Schedule

Project will be complete by 2015-10-31

Related Projects

None

Reference Documents

Approved Planning Study : http://WPG-APPS-369/PROD/CopperLeaf5/docs/1/DER-B14-01.pdf

CAPITAL PROJECT JUSTIFICATION
FOR

Relocate L17 to Semple Stn. Underground

REVIEWED BY:
(Owning Dept Manager)
KBraid 2014-09-18

NOTED BY:
(if applicable) 2014-09-16

Coordinating Division: JHunt 2014-09-16

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:
Charles Steel 2014 09 16

Business Unit V.P.:
2014-10-07

BUDGET $: (Total Net Cost)	$2,300,000
START DATE: (1st Cost Flow)	2014 09
IN-SERVICE DATE: (Last Major In-service Date)	2015 05

OWNING DIVISION: G13800 / Distribution Eng & Construction Division

I.M. NODE NUMBER: 1.1.3.10.10.1

W.B.S. NUMBERs: P:23621

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Young, Tyler T.Y. 2014-09-17 2014-09-12

DATE PREPARED: 2014 08 12

REPORT NUMBER: 9620

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☒ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ YES ☒ NO

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Relocate L17 to Semple Stn. Underground

Recommendation

Install 24kV feeder L17 underground from McPhillips Station to Semple Station for an estimated cost of $2,300,000 and an in-service date of May 2015.

Project Scope

The scope of this project includes:

- Install 7000m of 1000AL TRXLPE CTS cable between McPhillips and Semple Stations.
- Remove existing L17 termination (connected to existing overhead line) at McPhillips Station.

This project does not include salvage of the overhead L17 conductor or refurbishment of L18.

Background

In August 2013, Distribution Planning – Winnipeg recommended that refurbishment of both 24kV circuits L17 and L18 between McPhillips and Semple Stations be completed as per the Distribution Asset Maintenance (DAM) work order P:21571, estimated at a cost of $1,026,444. This project was justified on the basis of resolving the reliability concerns that had caused major outages on these feeders in recent years. The two circuits share a common wood pole line from McPhillips Street Station to supply both Kingsbury and Semple Stations. The supply to these stations is radial, i.e. there are not other supplies to these stations, and outages on one line can affect the other.

After consultation with Winnipeg Overhead Construction and Customer Service Operations, it was determined that an underground solution had merit. Project alternatives were re-examined in June 2014.

Justification

The Recommendation, to relocate L17 underground, will improve reliability to Kingsbury and Semple Stations. The present reliability concerns will be resolved in the future as the new underground circuit (L17) provides the ability to maintain supply to Kingsbury and Semple Station while outage causes to the overhead line (L18) are investigated and addressed. Presently, the overhead line outages can affect both circuits. There are insufficient feeder ties to other stations to supply all load from Kingsbury and Semple Stations, therefore, for outages affecting both lines, all customers from these stations are without power until the outage cause is determined and restoration of the system begins. This complete relocation would be consistent with the scope of the original Distribution Asset Maintenance project, and also defers the necessity to refburbish L18 at this time.

Relocating L17 underground enables de-energization of L18 for operations, maintenance or construction, as all load can be transferred to the underground cable. Distribution Operations and Construction resources will be able to work on these lines without assistance required for hot line work on the 24kV system.

As an alternative, a new 66kV-24kV DSC was proposed, to be located near the North End Water Pollution Control Centre (NEWPCC), to provide an alternate supply to Semple Station and improve reliability.

Justification
However, land is not immediately available to pursue this option and there is insufficient 66kV capacity in the area. Therefore, this option is not recommended. This project supports the Customer Service and Distribution business goals to "Provide Exceptional Customer Value". Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Rel. – Outage-Related (F3)	Op. Enhancement (FT)	Asset Sustainment (HB)	100%	$2,300,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.3%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Relocate L17 Underground	$(2,296,000)

Other Alternatives Considered	NPV Benefits/(Costs)
Install DSCs to Alternately Supply Semple Station Keewatin CSC had previously proposed a new 66kV-24kV DSC, to be located near the North End Water Pollution Control Centre (NEWPCC), to provide an alternate supply to Semple station and improve reliability. However, land is not immediately available to pursue this option and there is insufficient 66kV capacity in the area. Therefore, this option is not recommended.	$(3,900,000)
Refurbish L17 & L18 Overhead CS&D construction crews are unable to safely refurbish energized 24kV circuits located on the same pole line.	$(1,026,444.11)

Risk Analysis
None.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2014/15	$ 1,600,000
2015/16+	$ 700,000
Total	$ 2,300,000

Proposed Schedule

September 2014: Complete protection review of Semple Station reconfiguration.

January 30 2015: Complete design of L17 relocation underground.

February 2015: Construction begins.

May 30 2015: Project in-service date.

Related Projects

None.

Reference Documents

Planning memo dated 2014 09 10, "Relocate L17 Underground", T. Young to K. Braid
http://csd.hydro.mb.ca/dec/projects/Archieve/P23621-%20Relocate%20L17%20to%20Semple%20Stn%20Underground/Relocate%20L17%20Underground%20FINAL.PDF

CAPITAL PROJECT JUSTIFICATION FOR

Winnipeg Area 66 kV Line Upgrades

REVIEWED BY: A Vernh 2014 05 28
(Owning Dept Manager)
KBraid 2014 05 28

NOTED BY: 2014-05-28
(if applicable) John Hunt 2014-05-28

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:
Charles Stueh 2014 05 30

Business Unit V.P.:
Brent Reif 2014-06-05

BUDGET $: (Total Net Cost)	$2,031,000
START DATE: (1st Cost Flow)	2014 04
IN-SERVICE DATE: (Last Major In-service Date)	2019 12

OWNING DIVISION: G13800 / Distribution E&C Winnipeg

I.M. NODE NUMBER: 1.1.3.10.12.1

W.B.S. NUMBERs: P:23255, P:23258, P:23259, P:23260, P:23261, P:23268

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: T. Pickering T.P. 2014-05-28

DATE PREPARED: 2014 04 07

REPORT NUMBER: 9444

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☒ Safety
- ☒ System Supply
- ☐ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE: ☐ **YES** ☒ **NO**

Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Winnipeg Area 66 kV Line Upgrades

Recommendation

Upgrade 108 spans on Winnipeg area 66 kV lines BA10, TA11, DB2, R94, TD2, TD3, W3, and W4 to meet minimum clearance requirements, for a final project ISD of 2019 12 31 and a total project cost of $2,031,000.

Project Scope

1) Upgrade 55 spans on TD3, W3 and W4 with ISD 2014 12. (P:23255 - $896 K)
2) Upgrade 30 spans on R94, W3 and W4 with ISD 2015 12. (P:23258 - $410 K)
3) Upgrade 6 spans on BA10, TA11, TD2 and TD3 with ISD 2016 12. (P:23259 - $455 K)
4) Upgrade 5 spans on R94, DB2 and W4 with ISD 2017 12. (P:23260 - $60 K)
5) Upgrade 6 spans on R94 with ISD 2018 12. (P:23261 - $150 K)
6) Upgrade 6 spans on R94 with ISD 2019 12. (P:23268 - $60 K)

Background

In 2007, the following ten Winnipeg area 66 kV lines were surveyed using LIDAR technology: BA10, TA11, DB2, R94, TD2, TD3, W1, W2, W3, and W4. A report was issued in 2009 outlining the identified clearance violations, consisting of 108 spans on eight of the lines. In 2013, a planning study investigated the required improvements and recommended remediation.

Justification

In order to maintain minimum clearance requirements according to CSA standards, the lines must be de-rated or the violations must be eliminated. Loading on the affected lines does not make de-rating the lines a viable option. Eliminating the violations to maintain minimum clearance requirements ensures the safety of the public and MB Hydro staff.

This project aligns directly with our Corporate vision statement "To be the best utility in North America with respect to **safety**, rates, reliability, customer satisfaction and environmental leadership, and to always be considerate of the needs of customers, employees, and stakeholders. This project also supports CS&D Business Plan Goals: "Improve **safety** in the workplace" and "Provide exceptional customer **safety** and value".

Capital Investment Categorization:

Goal	Category	Sub- Category	Split
Safety	Public Safety	Asset Improvement	50%
Reliability-Load Related	Capacity Enhancement	Asset Improvement	50%

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.05%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
Upgrade 108 spans on Winnipeg area 66 kV lines BA10, TA11, DB2, R94, TD2, TD3, W3, and W4 to meet minimum clearance requirements, for a final project ISD of 2019 12 31 and a total project cost of $2,031,000.	($1,920,423)

Other Alternatives Considered	**NPV Benefits/(Costs)**
As this is a safety initiative no alternatives were considered.	

Risk Analysis

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	-
2014/15	$	896
2015/16	$	410
2016/17	$	455
2017/18+	$	270
Total	$	2,031

Proposed Schedule

For each year from June 2014 to December 2019:
Jun/Jul Design
Aug/Dec Construction

Related Projects

None

Reference Documents

[1] T. Pickering, "Winnipeg Area 66 kV Line Upgrades - Part 1," MB Hydro, Wpg., MB, September 2013.

Link: http://csd.hydro.mb.ca/dec/dpw/66kV%20Reports/SIES%20-%20Winnipeg%20Area%2066%20kV%20Line%20Upgrades_Part%201.pdf

CAPITAL PROJECT JUSTIFICATION FOR

Neepawa 66 kV Improvements

REVIEWED BY: GVerch 20140403
(Owning Dept Manager)
Glenn R Parkhouse 20140328
Chuck Steel, P.Eng. 2014 04 15

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: APRIL 16, 2014

Business Unit V.P.: May 23/14

BUDGET $: (Total Net Cost)	$9,501,000
START DATE: (1st Cost Flow)	2014 05
IN-SERVICE DATE: (Last Major In-service Date)	2016 10
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: Distribution E&C Rural

I.M. NODE NUMBER: 1.1.3.11.2.1

W.B.S. NUMBERs: P:22996, P:22997, P22998

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: G. Verch GV 2014 04 03

DATE PREPARED: 2014 02 10

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☒ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☐ **YES** ☒ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Neepawa 66 kV System Improvements.

Recommendation

Install a new 66 kV Line 759 from Neepawa Station which requires 27 km of 66 kV line from Neepawa South Station to Plumas Tap, a 66 kV steel bay and breaker at Neepawa South Station the terminate the new line and rebuild 16 km of Line 81 from Neepawa Station to SW9-15-16W.

Project Scope

1) Rebuild 16 km section of Line 81 from Neepawa South to SW 9-15-16 W. (P:22996 - 2.2 M)
2) New Line 759 from Neepawa South Station to L85 at Plumas Tap (P:22997 - $5.8 M)
3) New 66 kV Steel Bay and Breaker at Neepawa south Station (P:22998 - $1.5 M)

The in service date for phase 1 is 2014-10. The in service date for phase 2 and 3 is 2016-10.

Background

L85 is the second longest 66 kV line, and is the fourth worst performing 66 kV line in terms of outage frequency per year, part of which is attributed to the line's length. Splitting L85 into two separate lines was recommended in System Planning report SPD 2009/11 [1] and further justified in planning memo Neepawa System Improvement Recommendations [2].

Reconductoring of part of Line 81 is recommended to address low voltage concerns on Line 81, and to address aging infrastructure concerns as the line is 65 years old.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The requirement for the Neepawa Area System Improvements is as follows:

- The length of L85 causes a large amount of line exposure related outages to the communities of Gladstone, Plumas, Amaranth, Langruth, and Westbourne. TCPL also has a pumping station supplied by L85.
- L81 has low voltage problems due to sections of of 2/0 ACSR and #1CCSR conductor. This section of line is 65 years old. The line rebuild will address the low voltage issues and replace a section of line that has reached the end of life.

Capital Investment Categorization:

Goal	Category	Sub-Category	Split
Reliability – Outage-related	Operational Enhancement	New Asset Addition	65%
Reliability – Load-related	Capacity Enhancement	Asset Improvement	12.5%
Reliability – Outage-related	Aging Infrastucture	Asset Improvement	12.5%

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.05%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Construct a new 27 km 336 Line. Install a new 66 kV steel bay, breaker, and associated equipment at the new Neepawa 230-66 kV station to terminate the new line. Rebuild 16 km of L81.	($9,081,382)

Other Alternatives Considered	NPV Benefits/(Costs)
Rebuild L85 Rebuild 16 km of L81	($20,508,711)
Construct a new 27 km 336 Line. Install a new 66 kV steel bay, breaker, and associated equipment at the new Neepawa 230-66 kV station to terminate the new line. Install 10 MVAR capacitor at Erickson Station	

Risk Analysis

Capital Budget Estimate

Summarize the total capital net cost for the project in thousands of dollars (per the CERs – see Excel table below). CPJs for Major items must be accompanied by at least draft CERs, while CPJs for Domestic items must be accompanied by final CERs.

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2014/15	$	2,200
2015/16	$	1,950
2016/17	$	5,351
2017/18+	$	-
Total	$	9,501

Proposed Schedule

Related Projects

I.M.Node 1.1.2.3.0.1 "Neepawa 230-66kV Station"

Reference Documents

[1] Report, SPD 2009/11, "Neepawa Area System Improvement Study", 2009-08.
[2] Memo, Neepawa System Improvement Recommendations, 2014 01
Report, System Improvement & Expansion Study: Neepawa Area, 2013 05

CAPITAL PROJECT JUSTIFICATION FOR

WHITESHELL STATION BANK 1 REPLACEMENT

REVIEWED BY: David Swatek
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: 2014/02/24

Constructing Division:

Designing Division:

Financial: 2014.01.07

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Gerald Neufeld. 2014 02 20

Business Unit V.P.: A. Bailey 2014 02 27

BUDGET $: (Total Net Cost)	$3,027,000
START DATE: (1st Cost Flow)	2016 04
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	2017 11
RISK MATRIX/ BUSINESS CASE TIER:	Tier 3 (700 points)
INVESTMENT REASONS:	Capacity Enhancement (100%)

OWNING DIVISION:	TRANSMISSION PLANNING & DESIGN
I.M. NODE NUMBER:	1.1.2.3.19.1
W.B.S. NUMBERS:	P:19764
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	J.S. 2014-01-21 Joshua Shewchuk – Project Owner; Ty Nguyen – Project Manager
DATE PREPARED:	2013 09 27 TN 2014-01-21
REPORT NUMBER:	SPD 2010/08
FILE NUMBER (Optional):	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE * ☐ **YES** ☒ **NO**

* Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Whiteshell Station Bank 1 Replacement

Recommendation
Establish a new Base Capital-Core item to replace Whiteshell Station Bank 1 with a new 115-33x66kV 30MVA Power Transformer. Total Net Cost is estimated at $3,027,000 for an in-service of November 2017.

Project Scope

The project scope includes the following:
- Purchase and install a 115-33x66kV 30MVA Power Transformer in Bank 1 position with an OLTC range and a de-energized tap changer range compatible with existing Bank 2. This portion of the work has a Gross estimate of $2,706,000
- Salvage 115-33kV Bank 1 Power Transformer and associated 33kV Step Voltage Regulator, six 115kV Bank 1 and 2 Current Transformers and three 115kV Bank 1 Arrestors. This portion of the work has a Gross estimate of $51,000.

The total Gross estimate for the above is $2,757,000. Forecast escalation is estimated at $217,000 and capitalized interest is estimated at $52,000, making the Total Net Cost equal to $3,027,000.

Background

System Planning report SPD 2010/08 identified that load growth in the Whiteshell area has exceeded the station firm capacity. Whiteshell Station serves load from Atomic Energy of Canada Limited (AECL), which has increased in recent years. System improvements are required to supply the existing load and the requested increase in load from AECL.

Whiteshell Station has two 115-33kV banks with a 15/20 MVA and 18/24/30 MVA rating. Bank 1 is 50 years old and has passed its design life. Also, the separate stand-alone voltage regulator for Bank 1 has a history of problems.

The study specified an in-service date of October 2012 for the replacement of Bank 1. However, some of the key resource areas needed on this project are already fully committed on other higher-priority projects over the next several years, such that the start date for this project has been assumed to occur no earlier than April 2016. Allowing approximately 17 months to specify and deliver the transformer and three months for installation and commissioning, the estimated in-service date is November 2017.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The absence of firm transformation at Whiteshell Station could cause customer outages in the area during a transformer outage. A single contingency outage of Bank 2 could result in the existing Bank 1 transformer capacity being overloaded during winter peak. It is anticipated the associated customer outage would be greater than 20 hours. There is no 115-33kV transformer spare of comparable size, and repair of a failed

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

transformer could take up to two years. There are no other 33kV stations in the area to provide backup or transfer capability. Deferral of this project will place customers at risk of no supply.

The long term goal of Whiteshell Station and surrounding area is to convert from 33kV supply to 66kV supply which necessitates ensuring that any improvement to Whiteshell 115-33kV transformation is adequate for future 66kV conversion. The recommended Bank would match existing Bank 2 and hence facilitate this future conversion.

This project supports the Corporate goal of "Provide customers with exceptional value" and Transmission goal of "Provide customers with reliable power".

Capital Investment Categorization:
See link for instructions: http://t.hydro.mb.ca/tclm/tp/Capital%20Project%20Justification%20CPJ/Capital%20Investment%20Categorization.doc

Driver	Category	Sub-category	Split	Amount
Reliability: Load-related	Capacity Enhancement	Asset Improvement	100%	$3,027,000

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	5.40%	For current corporate rates see G911 For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Replace 115-33kV Bank 1 with a new 115-33x66kV 30MVA Power Transformer in the Bank 1 position at Whiteshell Station.	($2,249,000)

Other Alternatives Considered	NPV Benefits (Costs)
No other alternatives were covered by the study.	

Project Risk Analysis

A total of $287,000 for Contingency has been included in the project estimate, which is approximately 12% of the base expenditures. The following are the more significant risk items and associated estimate:

- Potential cost increase due to power transformer price escalation and using third party for inspection and witness testing ($149,000).
- Potential cost increase for civil, overhead line and electrical construction due to inclement weather and switching delay ($84,000).
- Potential cost increase due to design change, requirement of additional steel and material price escalation ($38,000).

Capital Budget Estimate

The annual and total net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2013/14	$	-
2014/15	$	-
2015/16	$	-
2016/17	$	372
2017/18	$	2,636
2018/19	$	18
2019/20	$	-
Total	$	3,027

Proposed Schedule

The key milestones are as follows:

Project Start	April 2016
Power Transformer Ordered	July 2016
Detailed Design	April 2016 to March 2017
Material Procurement	June 2016 to June 2017
Power Transformer Delivered	August 2017
Construction	September to October 2017
Commissioning	November 2017

Related Projects

None.

Reference Documents

SPD 2010/08, "Whiteshell Station Bank 1 Replacement", H. Sawhney, July 2, 2010.

Section:	Tab 4	**Page No.:**	pp. 2&3 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Project Justification (CPJ)		
Issue:	Understand CPJ and prioritization process		

PREAMBLE TO IR (IF ANY):

A Capital Project Justification is initiated when a capital project is identified as it is stated on page 2 of 26 tab 4. The CPJ contains information that identify the needs for the project. Furthermore; CPJs are examined to confirm the need based on a number of criteria. In addition, Manitoba Hydro assesses the proposed projects and whether projects of lesser priority can be displaced.

QUESTION:

Please provide a list of all the projects where total projects costs changed in CEF14 and their total cost exceeds $10M and provide an explanation for the change.

RATIONALE FOR QUESTION:

Confirm the prudence and reasonableness of the new projects included in the CEF 2014 and test whether cost effective prioritization is taking place. Does not duplicate PUB/Hydro 1-17 – 1-26.

RESPONSE:

Please see the response to PUB/MH-I-25a.

Section:	Tab 4	Page No.:	pp. 2&3 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Project Justification (CPJ)		
Issue:	Understand CPJ and prioritization process		

PREAMBLE TO IR (IF ANY):

A Capital Project Justification is initiated when a capital project is identified as it is stated on page 2 of 26 tab 4. The CPJ contains information that identify the needs for the project. Furthermore; CPJs are examined to confirm the need based on a number of criteria. In addition, Manitoba Hydro assesses the proposed projects and whether projects of lesser priority can be displaced.

QUESTION:

Please provide the methodology in working Excel format if available for the prioritization analysis, and provide an example on how Manitoba Hydro changes the priority of a project based on established criteria.

RATIONALE FOR QUESTION:

Confirm the prudence and reasonableness of the new projects included in the CEF 2014 and test whether cost effective prioritization is taking place. Does not duplicate PUB/Hydro 1-17 – 1-26.

RESPONSE:

Please see the response to COALITION/MH-I-11a which describes the overall framework for the evaluation and prioritization of Manitoba Hydro's capital expenditures. This response also describes the process for prioritizing individual projects and also the advancement and deferral of capital projects throughout the year to address changing priorities while managing within approved funding levels.

Section:	Tab 4	Page No.:	pp. 2&3 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Project Justification (CPJ)		
Issue:	Understand CPJ and prioritization process		

PREAMBLE TO IR (IF ANY):

A Capital Project Justification is initiated when a capital project is identified as it is stated on page 2 of 26 tab 4. The CPJ contains information that identify the needs for the project. Furthermore; CPJs are examined to confirm the need based on a number of criteria. In addition, Manitoba Hydro assesses the proposed projects and whether projects of lesser priority can be displaced.

QUESTION:

Please list and describe all the criteria used by Manitoba Hydro in the prioritization process, other than to maintain the overall funding levels within the Manitoba HydroEB approved CEF limits.

RATIONALE FOR QUESTION:

Confirm the prudence and reasonableness of the new projects included in the CEF 2014 and test whether cost effective prioritization is taking place. Does not duplicate PUB/Hydro 1-17 – 1-26.

RESPONSE:

Please see Manitoba Hydro’s response to COALITION/MH-I-11a.

Section:	Tab 4	**Page No.:**	pp. 2&3 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Project Justification (CPJ)		
Issue:	Understand CPJ and prioritization process		

PREAMBLE TO IR (IF ANY):

A Capital Project Justification is initiated when a capital project is identified as it is stated on page 2 of 26 tab 4. The CPJ contains information that identify the needs for the project. Furthermore; CPJs are examined to confirm the need based on a number of criteria. In addition, Manitoba Hydro assesses the proposed projects and whether projects of lesser priority can be displaced.

QUESTION:

Please provide the CEF limits and projects that were re-prioritized during CEF 2013 to meet those limits.

RATIONALE FOR QUESTION:

Confirm the prudence and reasonableness of the new projects included in the CEF 2014 and test whether cost effective prioritization is taking place. Does not duplicate PUB/Hydro 1-17 – 1-26.

RESPONSE:

The sustaining capital expenditure targets or limits established in CEF 2013 for additions, improvements and replacements of generation, transmission and distribution assets totaled $558 million for 2015 and $573 million for both 2016 and 2017.

As part of the capital planning process, projects are selected and approved that best mitigate the risks to the corporation with consideration for available capital funding, timelines for project completion and resource availability.

During the planning process for CEF13 a number of projects were re-prioritized taking into consideration operational and business risk. Examples include:

- The Laverendrye-St. Vital 230 kV transmission line was deferred by one year, from February 2017 to February 2018, recognizing that the line is a safeguard against a high consequence but low probability event and as such the deferral was deemed an acceptable short term risk.
- The rebuild of 20 km of 115kV transmission line (Laverendrye-Harrow) was deferred by five months from July 2016 to December 2016. The rebuild of the line represents phase 1 of the Southwest Winnipeg 115kV transmission improvements and was deferred to coincide with phase 2 (rebuild of 14 km of 115kV transmission line (St. Vital-Stafford). The additional five months of risk for single contingency overloads on the 115kV lines in the area was deemed acceptable.
- Slave Falls Units 1 & 2 major overhaul was deferred to 2019. While these units have a high probability of failure, the risk to lost generation is lower in comparison to other projects given the size of the units.

Following approval of the overall portfolio of projects, it is recognized that regular scheduling/prioritization adjustments are required due a number of factors including timing and nature of new customer requests, localized plant failures and other reliability issues, timing associated with property acquisitions or material procurement as well as required labour re-deployment across the province. Given the large number of individual projects and programs of varying magnitude, re-prioritization of project schedules is routinely managed.

Please see PUB/MH-I-18d for further discussion on the deferral and prioritization processes.

Section:	Tab 4	**Page No.:**	p. 5 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Change in Cost Flow from CEF 2013 to CEF 2014		
Issue:	Information related to figures 4.3 and 4.4		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce Figure 4.3 and Figure 4.4.

RATIONALE FOR QUESTION:

Test analysis of change in cost flow.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH- I-82-85, 90-91-ElectronicFormat.xlsx, sheet ‘Coalition 82’.

Section:	Tab 4	**Page No.:**	p. 6 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Change in Cost Flow from CEF 2013 to CEF 2014		
Issue:	Information related to figure 4.5		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

The updated figure to include the Major New Generation & Transmission expenditures forecast for 2012/2013 and 2013/2014 next to the actual expenditures.

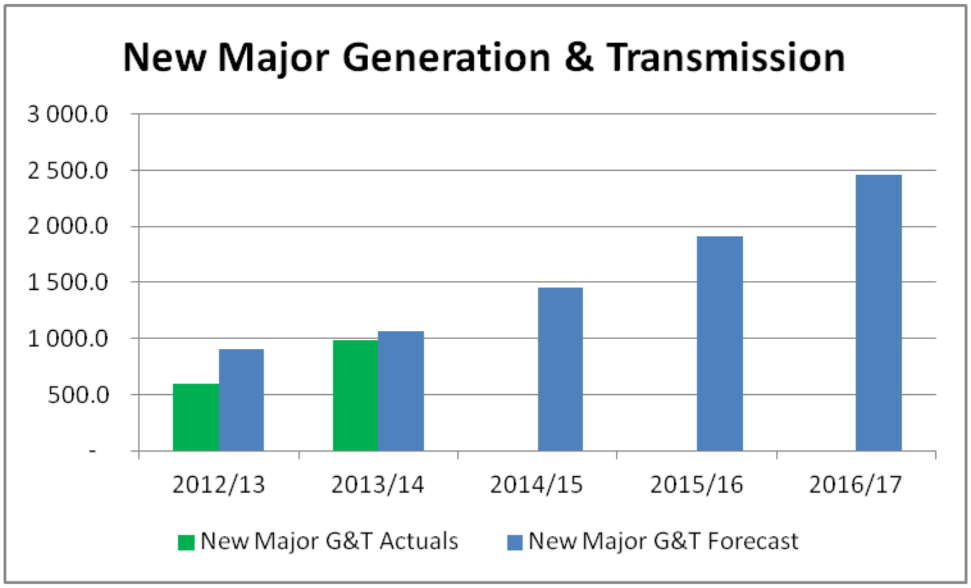
RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014.

RESPONSE:

Please see the following graph, which has been updated to include 2012/13 and 2013/14 forecast information from CEF12 and CEF13, respectively.

Manitoba Hydro has provided the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet ‘Coalition 83a&b’ for the electronic format.


New Major Generation & Transmission
3 000.0
2 500.0
2 000.0
1 500.0
1 000.0
500.0
-
2012/13
2013/14
2014/15
2015/16
2016/17
New Major G&T Actuals
New Major G&T Forecast

Section:	Tab 4	Page No.:	p. 6 of 26
Topic:			
Subtopic:	Change in Cost Flow from CEF 2013 to CEF 2014		
Issue:	Information related to figure 4.5		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

The data file or files used to produce Figure 4.5.

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85,90-91-ElectronicFormat.xlsx, sheet ‘Coalition 83a&b’.

Section:	4	**Page No.:**	p. 7 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Major New Generation & Transmission Capital Expenditure Forecast		
Issue:	Information related to figure 4.6		

PREAMBLE TO IR (IF ANY):

Figure 4.6 denotes the major new generation & transmission expenditures forecast CEF 2014. The questions below request information related to that figure.

QUESTION:

Please provide, in electronic format with all formulae intact, the data file or files used to produce Figure 4.6

RATIONALE FOR QUESTION:

Clarify calculation "target adjustment" line item.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment COALITION-MH I-84a-Attachment 1.xlsx, sheet 'Coalition 84a'.

Section:	4	Page No.:	p. 7 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Major New Generation & Transmission Capital Expenditure Forecast		
Issue:	Information related to figure 4.6		

PREAMBLE TO IR (IF ANY):

Figure 4.6 denotes the major new generation & transmission expenditures forecast CEF 2014. The questions below request information related to that figure.

QUESTION:

Please explain the "target adjustment" line item and how it is calculated.

RATIONALE FOR QUESTION:

Clarify calculation "target adjustment" line item.

RESPONSE:

Major New Generation and Transmission (MNG&T) projects are managed within approved scope and total budget. Annual estimates reflect the project schedule and incorporate the best available information at a point in time. Changes in annual spending are impacted by a number of factors including advancement and delays in the receipt of material and equipment, availability of resources, timing of regulatory approvals and impacts of weather. Over time, these changes in annual spending at the project level due to timing of expenditures are expected to be reconciled prior to the in-service of the project. The target adjustment addresses these project level expenditure timing differences that impact total MNG&T planned spending in any one forecast year by continuously rolling over estimated under expenditures at the total MNG&T level, thus, not impacting total project costs.

Based on historical spending patterns, annual MNG&T capital expenditures are on average 10% under spent compared to budget. For the purposes of calculating the MNG&T target adjustment, it is assumed that 10% of the current year projected expenditures will be rolled-over into the next fiscal year. The net of the under expenditure rolled-over from the previous year and the 10% under expenditure from the current year forms the target adjustment as demonstrated in the table below.

Target Adjustment Calculation:				
(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24
MNG&T TOTAL (before Target Adj.)	1 613	1 965	2 525	11 683
Underexpenditure Rolled-Over from Prior Year	-	161	213	1 285
After prior year Rolled Amount	1 613	2 127	2 737	12 967
Current Year Underexpenditure Rolled-Over to Next Year (10% of above)	(161)	(213)	(274)	(1 297)
Target Adjustment (Net Underexpenditure Roll-Over)	**(161)**	**(51)**	**(61)**	**(12)**
MNG&T TOTAL (after Target Adj.)	1 452	1 914	2 463	11 671

Section:	4	**Page No.:**	p. 7 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Major New Generation & Transmission Capital Expenditure Forecast		
Issue:	Information related to figure 4.6		

PREAMBLE TO IR (IF ANY):

Figure 4.6 denotes the major new generation & transmission expenditures forecast CEF 2014. The questions below request information related to that figure.

QUESTION:

Please explain how the costs are progressing each year starting from 2014/2015 for each line item. Provide your answer in electronic format with all formulae intact.

RATIONALE FOR QUESTION:

Clarify calculation "target adjustment" line item.

RESPONSE:

The Major New Generation and Transmission project capital expenditures found in Figure 4.6 progress through Construction in Progress to Plant in Service until the project is placed in service. Please see MIPUG/MH-I-11a for the progression of plant in-service for each project.

Please see the excel attachment COALITION-MH I-84c-Attachment 1.xlsx, sheet 'Coalition 84c' which provides the data for MIPUG/MH-I-11a through to 2023/24.

Section:	4	**Page No.:**	p. 7 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Major New Generation & Transmission Capital Expenditure Forecast		
Issue:	Information related to figure 4.6		

PREAMBLE TO IR (IF ANY):

Figure 4.6 denotes the major new generation & transmission expenditures forecast CEF 2014. The questions below request information related to that figure.

QUESTION:

Please explain the "other" line item and how it is calculated.

RATIONALE FOR QUESTION:

Clarify calculation "target adjustment" line item.

RESPONSE:

The other line is Generating Station Improvements and Upgrades in the CEF14 document. Generating Station Improvements and Upgrades under New Major G&T is a general provision for overhauls on the northern generating stations which increase capacity and/or generation. For long-term forecast purposes, general provisions are made to reflect expenditures that may be necessary to maintain the existing generating station, transmission and distribution systems but for which detailed planning and engineering has not been completed nor received specific project approval.

Section:	4	Page No.:	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

The sustaining capital expenditures forecast for 2012/2013 and 2013/2014

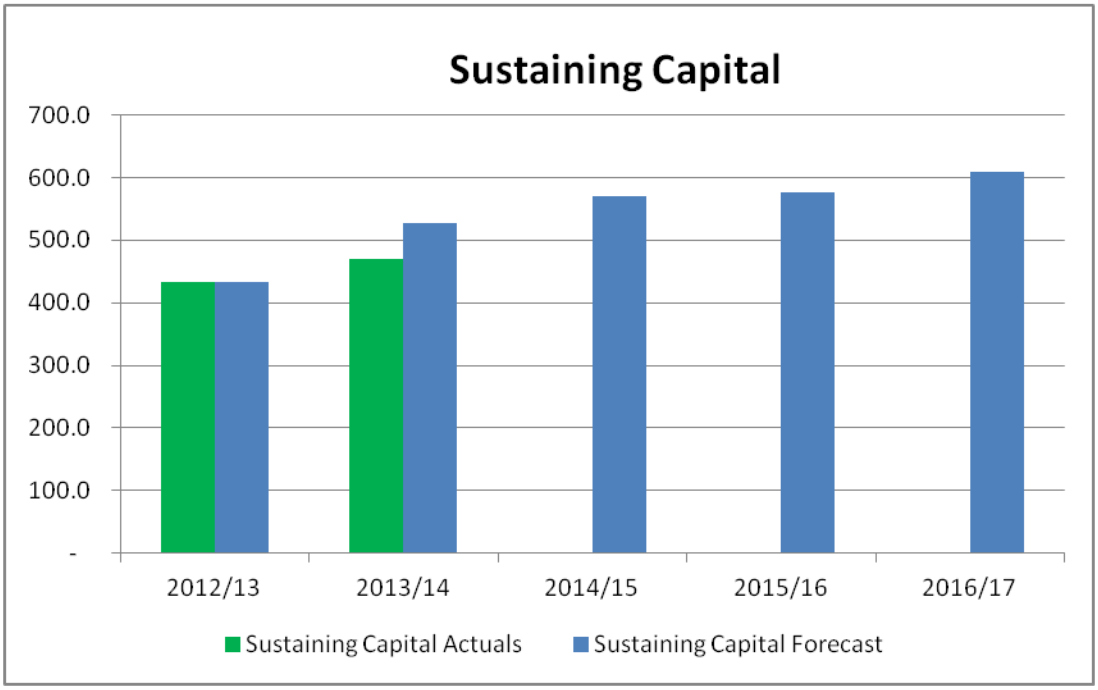
RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Please see the following graph, which has been updated to include 2012/13 and 2013/14 forecast information from CEF12 and CEF13, respectively.

Please see Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet ‘Coalition 85a&b’ for the electronic format.


Sustaining Capital
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2012/13
2013/14
2014/15
2015/16
2016/17
Sustaining Capital Actuals
Sustaining Capital Forecast

Section:	4	**Page No.:**	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

The data file or files used to produce Figure 4.11 with the formulae intact

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet 'Coalition 85a&b'.

Section:	4	**Page No.:**	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

The data file or files used to produce Figure 4.12 with the formulae intact

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet ‘Coalition 85c&d’.

Section:	4	**Page No.:**	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

For Figure 4.12, please provide the file or files with the formulae intact that describe how the cost is calculated for each asset type.

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85,90-91-ElectronicFormat.xlsx, sheet ‘Coalition 85c&d’.

Please see the response to PUB/MH-I-22c for a description of how the funds are allocated to each asset type.

Section:	4	**Page No.:**	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

Please update figure 4.12 to include the 2008 to 2014 and 2018 to 2024 time periods.

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Figure 4.12 was developed for this application to supplement the Electric Infrastructure Condition Assessment report on a forecast basis and is not available by asset type for actual expenditures from 2008 to 2014. Manitoba Hydro's financial system tracks capital expenditures by cost element and depreciation category.

Please refer to PUB/MH-I-22c for a breakdown of the forecast expenditures from 2018 to 2024.

Section:	4	Page No.:	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

Please provide a similar breakdown with the actual expenditures for 2014 and 2013

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Please see the response to COALITION/MH I-85e.

Section:	4	Page No.:	pp. 11&12 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining Capital Expenditures (Major & Base Capital)		
Issue:	Information related to figures 4.11 and 4.12		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format:

For Figure 4.12, please identify the major, base capital expenditures and reconcile against CEF14 totals.

RATIONALE FOR QUESTION:

Compare Forecast with actual expenditures for 2012/2013 and 2013/2014 and provide context for increased expenditure.

RESPONSE:

Please see the response to PUB/MH I-18g.

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment COALITION-MH I-85g-Attachment 1.xlsx, sheet ‘Coalition 85g’.

Section:	Tab 4	Page No.:	p. 19 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro Current and 20 year outlook Asset Health Index		
Issue:	Update figure 4.17 for short term horizon		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update figure 4.17 to include the 2014/15, 2015/16 and 2016/17 Manitoba Hydro AHI outlook and provide the supporting data file or files, in electronic format with all formulae intact.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and reasonableness of capital prioritization.

RESPONSE:

In order to provide a response within the available timeframe, Manitoba Hydro has prepared an outlook for a subset of the asset types for each year 2014/15 to 2017/18.

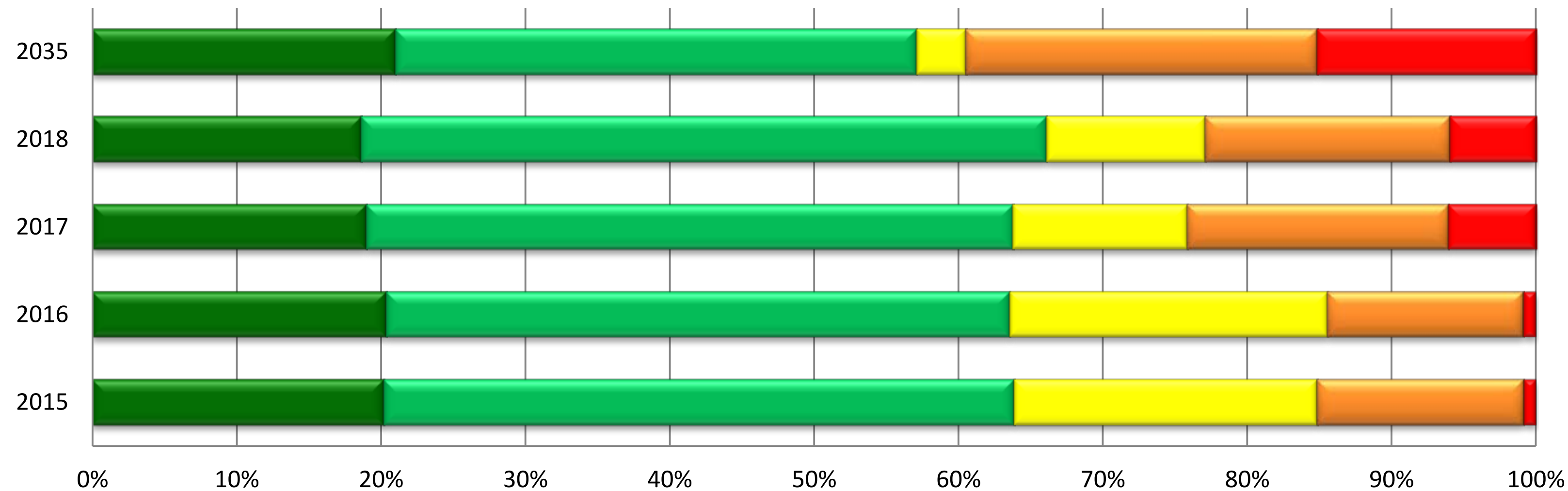
Generation asset information was chosen for this response as computer modeling is used to prepare this analysis for generation assets, which has enabled Manitoba Hydro to develop this response in the available time.

Please see the soccer field diagrams below for the forecast view of Generation asset condition for 2014/15 through 2017/18 and comparison with the 20 year forecast found in Figure 4.17 on page 19 of Tab 4.

Manitoba Hydro prioritizes capital spending on the highest risk assets, and as a result, the asset health in those asset categories will improve. With consideration to all risk factors and financial consequences, the Corporation expects to give priority to investment in governors, breakers and transformers. Therefore, the condition of these asset categories improves slightly over the three years in question. As generator, turbine and exciter asset categories are expected to receive a lower priority, those assets can be expected to experience a decline in condition.

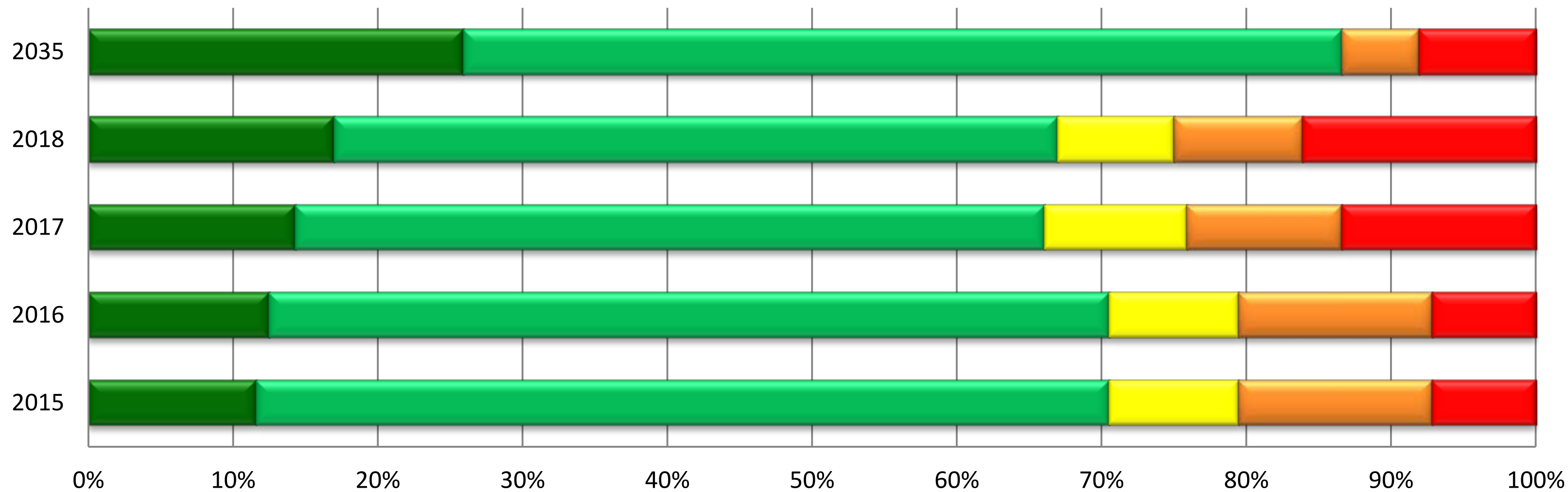
The impacts of asset degradation accumulate in the future years, beyond the four year time frame. This results in a greater proportion of poor and very poor asset conditions in 20 years, as illustrated in Figure 4.19. It is important to note, this analysis assumes funding levels reflective of CEF13, and accompanying indicative rate increases of 3.95% per year for each year of the forecast.

Generation Asset Condition Generator



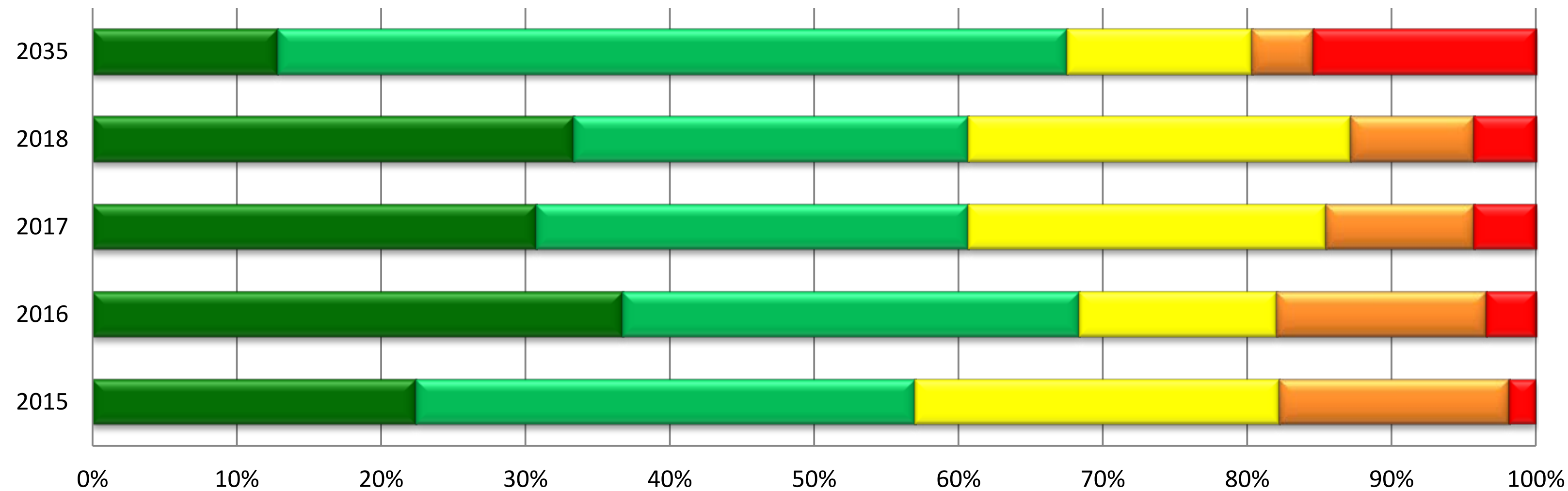
	2015	2016	2017	2018	2035
Very Good	24	24	22	22	25
Good	52	51	52	56	43
Fair	25	26	14	13	4
Poor	17	16	21	20	29
Very Poor	1	1	7	7	18

Generation Asset Condition Turbines



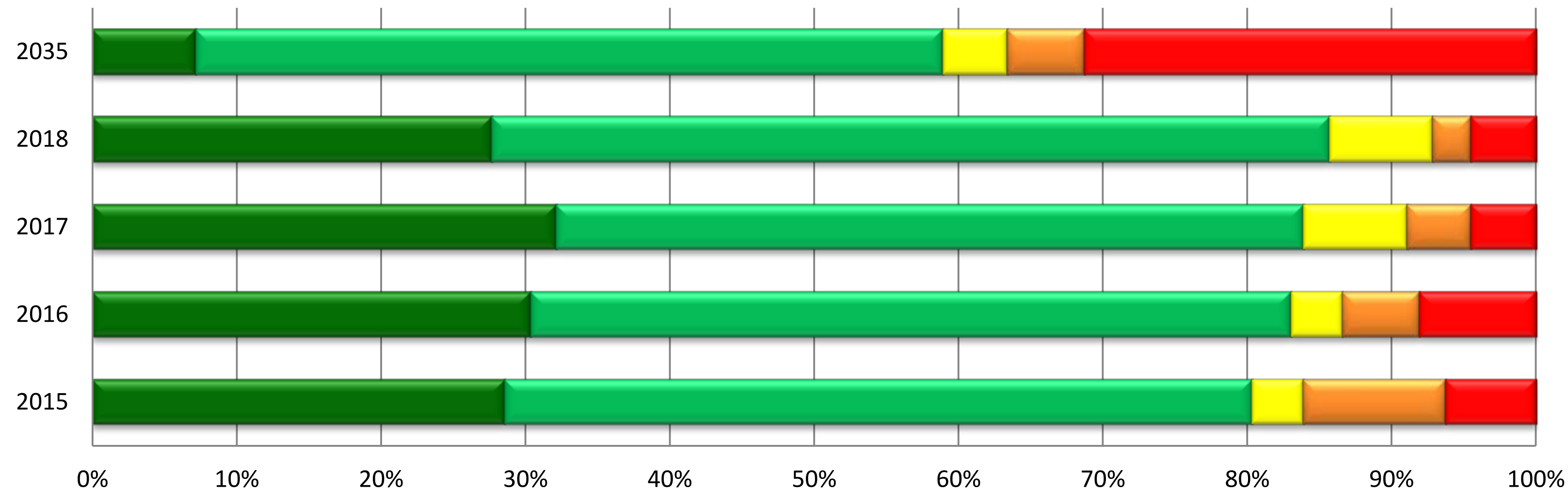
	2015	2016	2017	2018	2035
Very Good	13	14	16	19	29
Good	66	65	58	56	68
Fair	10	10	11	9	0
Poor	15	15	12	10	6
Very Poor	8	8	15	18	9

Generation Asset Condition Exciters



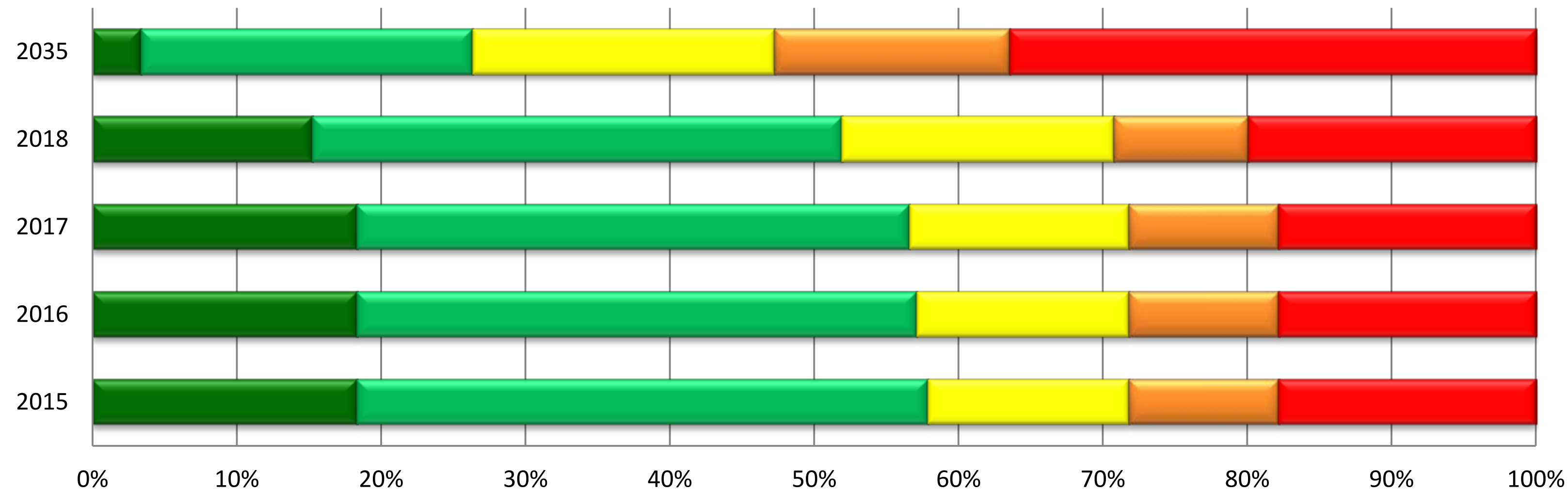
	2015	2016	2017	2018	2035
Very Good	24	43	36	39	15
Good	37	37	35	32	64
Fair	27	16	29	31	15
Poor	17	17	12	10	5
Very Poor	2	4	5	5	18

Generation Asset Condition Governors



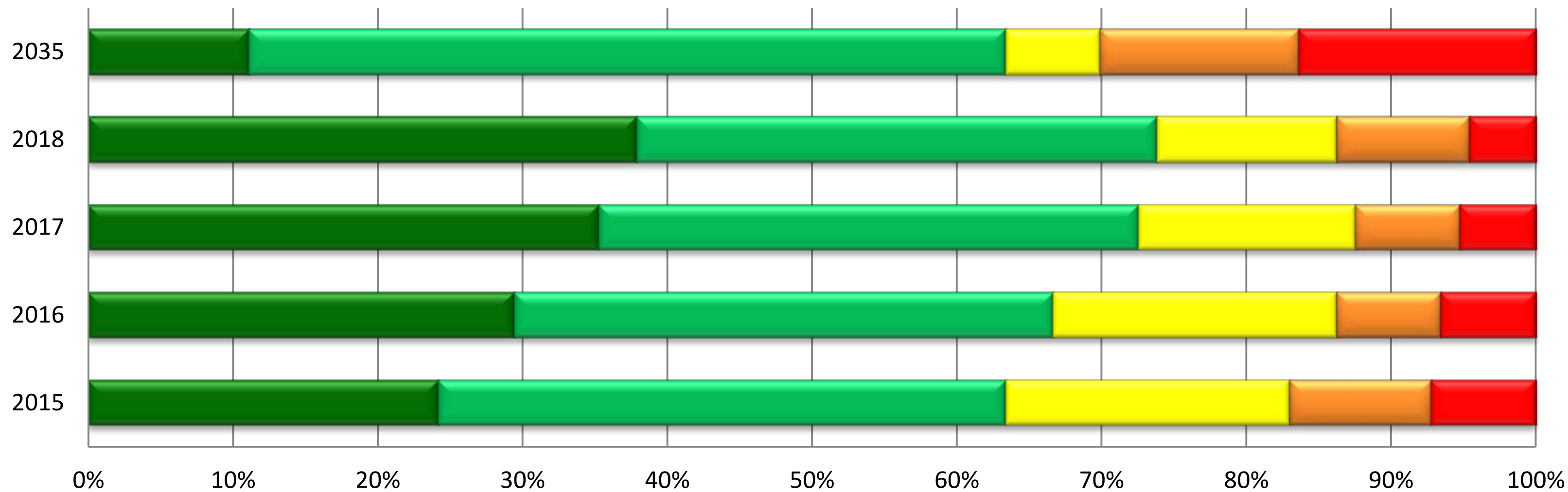
	2015	2016	2017	2018	2035
Very Good	32	34	36	31	8
Good	58	59	58	65	58
Fair	4	4	8	8	5
Poor	11	6	5	3	6
Very Poor	7	9	5	5	35

Generation Asset Condition Breakers



	2015	2016	2017	2018	2035
Very Good	71	71	71	59	13
Good	153	150	148	142	89
Fair	54	57	59	73	81
Poor	40	40	40	36	63
Very Poor	69	69	69	77	141

Generation Asset Condition Transformer



	2015	2016	2017	2018	2035
Very Good	37	45	54	58	17
Good	60	57	57	55	80
Fair	30	30	23	19	10
Poor	15	11	11	14	21
Very Poor	11	10	8	7	25

Section:	Tab 4	Page No.:	p. 19 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro Current and 20 year outlook Asset Health Index		
Issue:	Update figure 4.17 for short term horizon		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the complete copy of the scoring method used to classify each asset class from “Very Good” to “Very Poor”.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and reasonableness of capital prioritization.

RESPONSE:

Please see Manitoba Hydro’s response to COALITION/MH-I-96 a.

Section:	Tab 4	**Page No.:**	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide Figure 4.16 in fully functioning electronic spreadsheet format with all supporting data.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

Pursuant to Order 33/15, the PUB ordered that it will not require Manitoba Hydro to file electronic models or spreadsheets with formulae intact and advised that it would follow the PUB's past practice not to require electronic models.

Manitoba Hydro has however, provided the information in excel format. Please see the excel attachment to this response.

Section:	Tab 4	**Page No.:**	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

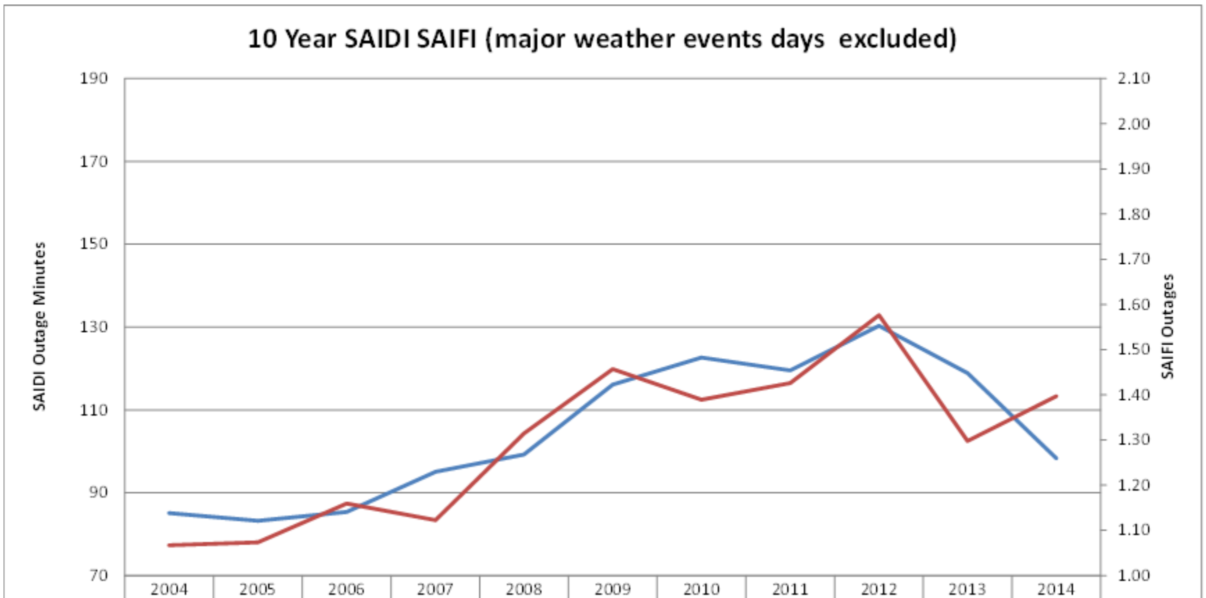
Please recreate Figure 4.16 to exclude major weather events, if that has not already been done.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

Please find below Figure 4.16 restated to exclude major weather events. Major weather event days are categorized as days that had > 2 million customer minutes and weather was the major contributor.



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIDI	85	83	85	95	99	116	123	120	130	119	98
SAIFI	1.07	1.07	1.16	1.12	1.31	1.46	1.39	1.43	1.58	1.30	1.40

The impact of major storms on SAIDI and SAIFI performance indicators varies from year to year, with 2012 performance greatly affected by large-scale storm activity. While the standard varies across Canadian utilities whether to include major storm activities, Manitoba Hydro chooses to incorporate major weather events into its performance. This is a result of storm activity with associated high winds or ice accumulation placing stress on electric plant, especially if aged and in poorer condition, and is believed to be a contributing factor to reliability performance in subsequent periods.

Section:	Tab 4	**Page No.:**	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

How does Manitoba Hydro factor SAIDI and SAIFI into its sustaining capital expenditures project selection?

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

Manitoba Hydro does not directly factor SAIDI and SAIFI reliability performance into its capital project selection process. However, projects or programs that are justified in whole or in part on the basis of maintaining system reliability are represented by these industry accepted performance measures.

Achieving Manitoba Hydro's targeted reliability frequency and duration performance is also dependent on other factors beyond the integrity of Manitoba Hydro's electric infrastructure. Some of these are beyond complete control of Manitoba Hydro and include tree contact, human element as vehicular contact with plant and foreign interference such as wildlife.

Section:	Tab 4	Page No.:	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the expenditures by year for Vegetation Management from 2004 to 2014.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

The vegetation management expenditures per year from 2005 to 2014 are as follows. Please note that expenditures for 2004 are not available.

Vegetation Management Expenditures (000's)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Chemical Treatment	$ 283	$ 140	$ 443	$ 330	$ 409	$ 455	$ 399	$ 482	$ 458	$ 533
Mechanical Clearing	640	600	667	1,024	890	1,114	1,043	1,316	1,477	1,578
Tree Trimming	1,237	1,615	2,003	2,424	2,777	3,027	3,102	2,888	2,563	3,491
Distribution General Projects	542	802	846	905	637	211	132	295	282	546
Total	**$2,702**	**$3,157**	**$3,959**	**$4,683**	**$4,713**	**$4,807**	**$4,676**	**$4,981**	**$4,780**	**$6,148**

Section:	Tab 4	Page No.:	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

What are the target SAIDI and SAIFI figures Manitoba Hydro hopes to achieve with its proposed capital expenditures, and which asset classes are relied upon to achieve these targets?

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

Manitoba Hydro's objective is to sustain or improve SAIDI and SAIFI performance within the established corporate approved targets. As described in COALITION/MH-I-7a and I-7b, these approved targets for SAIDI and SAIFI are currently <116 outage minutes and <1.4 outages per year. A review of these performance measures in comparison to the targets is undertaken annually to determine if any adjustments to the target values should be made. Since 2012, these targets have remained unchanged and at the present time, the current reliability performance targets are considered a sound representation of valued reliable service for Manitoba Hydro's customers.

While all generation, transmission and distribution asset classes as identified in Manitoba Hydro's Electric Infrastructure Condition Assessment Summary Report (Appendix 4.2), and as illustrated in Tab 4 Figure 4.17, impact reliability performance to some degree, the degradation of certain asset categories do have a more direct effect on SAIDI and SAIFI performance. These include:

- Transmission Breakers
- Transmission Transformers
- Transmission Wood Poles
- Distribution Station Breakers
- Distribution Station Transformers
- Underground Cables
- Distribution Wood Poles
- Overhead Distribution Transformers

Without required capital investment funding, the expectation is that both the performance of outage duration and outage frequency will gradually worsen as assets most directly related to sustaining SAIDI and SAIFI performance will degrade at accelerated rates.

Section:	Tab 4	**Page No.:**	p. 17 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro SAIDI and SAIFI Indicators		
Issue:	System performance measures and sustaining capital expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Discuss what other system performance targets Manitoba Hydro plan to reach with its proposed capital expenditures.

RATIONALE FOR QUESTION:

Assess how AHI develops in the short term and the reasonableness of prioritization.

RESPONSE:

Manitoba Hydro considers a number of system performance targets in the evaluation of its capital expenditure requirements, examples for the generation, transmission and distribution asset groups include:

- Expenditures for generation assets are directed to manage the risk of lost generation and to improve forced outage performance and unit availability. The objective is to achieve performance in line with the CEA average benchmark, however considering current replacement rates, achieving this target may take several years.

- Capital spending for transmission assets is directed at maintaining compliance with North American Electric Reliability Corporation (NERC) Reliability Standards, TPL-001 through TPL-004, while managing the impacts of load growth and aging infrastructure. Specific performance criteria used for transmission planning studies is provided in

Manitoba Hydro's Transmission System Interconnection Requirements (TSIR) document, publicly available on OASIS (http://www.oasis.oati.com).

- Manitoba Hydro is working towards reducing the percentage of overloaded distribution stations in Winnipeg to 20% by 2020 with a long term objective of ensuring that no stations exceed their maximum rating. Achieving this objective requires significant investments today and in the coming years. There are 97 distribution stations supplying the City of Winnipeg; 37 stations are currently loaded beyond their maximum capacity, and 26 stations are at or above 80% of their loading limit. The in-service dates of substation capacity projects can be deferred by transferring load to other, less loaded stations; however, the use of this strategy has been exhausted and is no longer practical.

Section:	Tab 4	**Page No.:**	p. 20 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Type Expectancy and Turnover at Current Replacement Rates		
Issue:	Confirm Manitoba Hydro's claim related to current replacement rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce Figure 4.18

RATIONALE FOR QUESTION:

Test Manitoba Hydro's claim of high turnover under current replacement rate.

RESPONSE:

The production of information contained in Figure 4.18 is a summary of expected life (in years) and turnover based on current replacement rates (in years) information illustrated in Section 4.0 of the Manitoba Hydro Electric Infrastructure Condition Assessment Summary for each asset category (Tab 4, Appendix 4.2 of the Application). The life expectancy and turnover rates for each asset category were based on internal subject matter expertise, industry interpretation and approximations of annual replacement rates over various time periods.

While Manitoba Hydro does track actual replacements for certain assets within an asset category, many assets have not yet been replaced since its original in-service necessitating current replacement rates to be based in part on qualitative interpretation and subjective assessment.

Please refer to COALITION/MH-I-88b and COALITION/MH-I-88c for the definition of current replacement rates and life expectancy of Manitoba Hydro's asset categories.

Section:	Tab 4	**Page No.:**	p. 20 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Type Expectancy and Turnover at Current Replacement Rates		
Issue:	Confirm Manitoba Hydro's claim related to current replacement rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the current replacement rate for each asset class as it is calculated by Manitoba Hydro.

RATIONALE FOR QUESTION:

Test Manitoba Hydro's claim of high turnover under current replacement rate.

RESPONSE:

Please see the response to MIPUG/MH I-36 for the definition of current replacement rates for each asset category.

The turnover (at current replacement rates) was provided on page 20 of of Tab 4 of the GRA which indicates that in many cases Manitoba Hydro has been operating and maintaining its assets well beyond their expected life.

Current replacement rates for each asset class identified in Figure 4.18 of Tab 4 are provided below and are measured in units per year.

Figure 4.18 Revised - Asset Type Life Expectancy and Turnover at Current Replacement Rate

Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)	QTY	Current Replacement Rate = #/ year
Generation	Generators	60	117	117	1.0
	Hydraulic Turbines	90-100	84	112	1.3
	Exciters	50-90	117	117	1.0
	Governors	20-125	50	112	2.2
	Breakers	60-65	129	387	3.0
	Transformers	40-70	150	153	1.0
Transmission	Transmission Breakers	60-65	149	343	2.3
	HVDC Breakers	60-65	58	258	4.4
	Transmission Transformers	40-70	152	259	1.7
	HVDC Transformers	40-70	70	29	0.4
	Transmission Structures	85	285	19796	70
	Transmission Wood Poles	75	255	18285	72
	Transmission Overhead Conductor	85	410	14301	35 km
	HVDC Converter Transformers	40-50	73	57	0.8
	HVDC Valve Group	25	48	39	0.8
	HVDC Synchronous Condensers	65	65	9	0.1
	HVDC Shunt Reactors	35	55	7	0.1
	HVDC Smoothing Reactors	25	30	20	0.7
Distribution	Station Breakers	60-65	180	1791	10
	Station Transformers	40-70	370	739	20
	Underground Cables	30-70	328	6069	19km
	Manholes	80	500	2409	4.8
	Ductlines	100	378	265	0.7 km
	Padmount Transformers	50	70	20435	292
	Wood Poles	70	200	1082873	5414
	Overhead Conductors	100	200	114882	574 km
	Overhead Transformers	75	70	145798	2083
	Street Lights	50-70	100	58225	582

Section:	Tab 4	**Page No.:**	p. 20 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Type Expectancy and Turnover at Current Replacement Rates		
Issue:	Confirm Manitoba Hydro's claim related to current replacement rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the source for the Life Expectancy column included in Figure 4.18.

RATIONALE FOR QUESTION:

Test Manitoba Hydro's claim of high turnover under current replacement rate.

RESPONSE:

The Life Expectancy of each asset is not based on a single source. It is an estimate using actual performance history of existing and replaced assets, industry knowledge and published data. The actual life expectancy of an asset can vary significantly based on factors including service history, environment and technology. The Life Expectancies in Figure 4.18 of Tab 4 are intended to illustrate the relative age when Manitoba Hydro's expects its electric assets will reach end of life.

Section:	Tab 4	Page No.:	p. 20 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Type Expectancy and Turnover at Current Replacement Rates		
Issue:	Confirm Manitoba Hydro's claim related to current replacement rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the schedule of replacements utilized to calculate the turnover at current replacement rates for each class. Compare the schedule with the actual replacements conducted in the past three years.

RATIONALE FOR QUESTION:

Test Manitoba Hydro's claim of high turnover under current replacement rate.

RESPONSE:

The following provides a schedule of the replacement rates for the last three years. Information for transmission assets is not readily available. It is important to note that the replacements conducted in the last three years are based on current priorities, and may not be indicative of the estimated replacement rates as identified in COALITION/MH-I-88b.

TURNOVER RATE -as provided in Tab 4	REPLACEMENT RATE assets replaced / year (estimated over 15 years) Used to calculate Turnover in Tab 4	ACTUAL ASSETS REPLACED (assets retired over the past 3 years)
GENERATORS		
117	1/year	2014 – Kelsey Unit 7 - Kettle Unit 4 2013 – Kelsey Unit 6 - Seven Sisters Unit 5 2012 – Kelsey Unit 3 - Great Falls Unit 2
TURBINES		
84	3 every 4 years	2014 – Kelsey Unit 7 2013 – Kelsey Unit 6 2012 – Kelsey Unit 3
EXCITERS		
117	1/year	2014 – Kelsey Unit 7 2013 – Kelsey Unit 6 2012 – Kelsey Unit 3
GOVERNORS		
50	2/year	No governors replaced between 2012-2014
BATTERY BANKS		
20	2/year	2014 – Kelsey Bank 1 - Pointe du Bois SWYD/CH 2013 – Kelsey Bank 2 - Laurie River 1+ 2 VFH 2012 – Kettle Bank 1 and 2 - Great Falls Bank A and B - Pine Falls Bank A and B

TURNOVER RATE -as provided in Tab 4	REPLACEMENT RATE assets replaced / year (estimated over 15 years) Used to calculate Turnover in Tab 4	ACTUAL ASSETS REPLACED (assets retired over the past 3 years)
BREAKERS		
129	3/year	2014 – Pine Falls 52 R3 - Pine Falls 52 R5 - Pine Falls 52 R7 - Pine Falls 52 R15 - Grand Rapid Unit 4 - Selkirk OBC R18 2013 – Pine Falls 52 R12 - Pine Falls 52 R14 - Pine Falls 52 R17 - Brandon R10 - Brandon R11 - Brandon R13 2012 – McArthur Falls R1 - McArthur Falls R4 - Pointe du Bois Bank 7 - Pointe du Bois Spare
Transformers		
150 years	1/year	2014 – Kettle T01 - Kettle T02 - Kettle T10 - Kettle T04 - Kettle T08 - Kettle Spare 2 2013 – Pointe du Bois Bank 7 - Pointe du Bois Bank 3 - Kettle T06 - Kettle T12 2012 – Pointe du Bois Bank 4 - Kelsey Unit 4

Distribution Asset	2012	2013	2014
Underground Cables	11.5km	12km	12.5km
Manholes	4.5	5	5.5
Ductline	670m	700m	725m
Padmount Transformers	240	250	260
Overhead Conductor	48km	50km	52km
Overhead Transformers	1,925	2,000	2,075
Poles	4,750	5,000	5,250
Street Lights	1,250	1,300	1,350

Section:	Tab 4 Appendix 4.1	**Page No.:**	p. 22 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro Current and 20 year outlook Asset Health Index		
Issue:	Replacement rates accounted for the 20 year outlook		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please identify the amount of asset replacements included in the Manitoba Hydro 20 Year outlook Asset Health Index graph.

RATIONALE FOR QUESTION:

Manitoba Hydro Outlook Figure 4.19 denotes a no replacement scenario and not a current replacement rate scenario.

RESPONSE:

Manitoba Hydro's Outlook as illustrated in Figure 4.19 denotes a current replacement rate scenario. This outlook was developed using one or more of current replacement rate information, extrapolation of planned programs and asset investment modeling.

While the quantity of assets in each category that are estimated to be replaced over the next 20 years will change based on updates to asset conditions and risk, where detailed analyses have been undertaken, the following table provides an estimation of these values at the present time:

Asset Category	Forecasted Replacement Quantities
Generators	37
Hydraulic Turbines	13
Exciters	47
Governors	28
Breakers	12
Transformers	58
Transmission Breakers	36
HVDC Breakers	0
Transmission Transformers	21
HVDC Transformers	0
Transmission Structures	0
Transmission Wood Poles	340
Transmission Overhead Conductors	63 km
HVDC Converter Transformers	10
HVDC Valve Groups	15
HVDC Synchronous Condensers	13
HVDC Shunt Reactors	0
HVDC Smoothing Reactors	0
Distribution Station Breakers	Not Available
Distribution Station Transformers	Not Available
Distribution Underground Cable	240 km
Manholes	100
Ductlines	14 km
Padmount Transformers	5,000
Distribution Wood Poles	100,000
Distribution Overhead Conductors	10,000 km
Distribution Overhead Transformers	40,000
Street Lights	11,200

Section:	Tab 4 Appendix 4.1	**Page No.:**	p. 22 of 26
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba Hydro Current and 20 year outlook Asset Health Index		
Issue:	Replacement rates accounted for the 20 year outlook		

PREAMBLE TO IR (IF ANY):

QUESTION:

Update figure 4.19 by using current replacement rates and provide the result in an electronic format file with the formulae intact.

RATIONALE FOR QUESTION:

Manitoba Hydro Outlook Figure 4.19 denotes a no replacement scenario and not a current replacement rate scenario.

RESPONSE:

Manitoba Hydro's 20 Year Outlook as illustrated in Figure 4.19 of Tab 4 (Page 22) indicates the projection of asset health for each category using current replacement rates.

Section:	Tab 4 Appendix 4.1	**Page No.:**	CEF 14 p. 2
Topic:	Capital Expenditure Forecast		
Subtopic:	Capital Expenditure Forecast CEF 14		
Issue:	Assess cash flow of Capital Expenditure Forecast CEF 14		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide, in electronic format with all formulae intact, the file or files used to produce the Capital Expenditure Forecast CEF 14 starting on page 2 and ending on page 8.

RATIONALE FOR QUESTION:

Supporting documentation for CEF 14.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet ‘Coalition 90 & 91ai-vi’.

Section:	Tab 4 Appendix 4.1	**Page No.:**	pp. 29-33
Topic:	Capital Expenditure Forecast		
Subtopic:	Base Capital – Electric Operations		
Issue:	Assess Manitoba Hydro's Target escalation		

PREAMBLE TO IR (IF ANY):

The generation, operations, transmission, customer service & distribution, customer care & energy conservation, Human Resource & corporate services and Finance & Regulatory sections of the electric operations include major and base target cash flows.

QUESTION:

Please provide, in electronic format with all formulae intact, the data file or files used to produce the target cash flows for the following electric operations:

i. Generation that include major and base
ii. Transmission
iii. Customer Service and Distribution
iv. Customer Care & Energy Conservation
v. Human Resources & corporate Services
vi. Finance and Regulatory

RATIONALE FOR QUESTION:

Assess Manitoba Hydro's Target escalation.

RESPONSE:

Manitoba Hydro is providing the requested information in Microsoft Excel or other writable format containing data only. Please see the excel attachment Coalition-MH I-82-85, 90-91-ElectronicFormat.xlsx, sheet 'Coalition 90 & 91ai-vi'.

Section:	Tab 4 Appendix 4.1	Page No.:	pp. 29-33
Topic:	Capital Expenditure Forecast		
Subtopic:	Base Capital – Electric Operations		
Issue:	Assess Manitoba Hydro's Target escalation		

PREAMBLE TO IR (IF ANY):

The generation, operations, transmission, customer service & distribution, customer care & energy conservation, Human Resource & corporate services and Finance & Regulatory sections of the electric operations include major and base target cash flows.

QUESTION:

Please explain why the 2% escalation was chosen.

RATIONALE FOR QUESTION:

Assess Manitoba Hydro's Target escalation.

RESPONSE:

The base target values are escalated at 2% reflecting the forecast CPI index. This assumes that increases in labour resources required due to growth and aging infrastructure are offset by productivity improvements. The resulting conservative inflationary increases are due to increases in wages, salaries and benefits, as well as the cost of materials and contracted services which have historically increased at rates greater than the generic goods and services included in CPI.

Section:	Tab 4 Appendix 4.2	Page No.:	p. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	Electric Infrastructure Condition Assessment Summary		
Issue:	Assets' Consequence of failure		

PREAMBLE TO IR (IF ANY):

The executive summary of the Electric Infrastructure Condition Assessment Summary report includes the following:

"In-service failures generally represent a greater risk of customer outages and/or load shedding and are a potential hazard to individuals working in and around these assets as well to public safety."

QUESTION:

Please describe how Manitoba Hydro incorporated into its risk management process the consequence caused by a failed asset in the Manitoba electric system. Include in your response a complete list of the consequence factors considered, the relative weight of each, copies of the criteria used for a manual scoring system (if any) and a fully functioning electronic copy of any software driven scoring system used (if any).

RATIONALE FOR QUESTION:

Evaluate whether Manitoba Hydro capital expenditure methodology included the consequence of failure of an asset.

RESPONSE:

Manitoba Hydro's Corporate Risk Management Report ("CRMR") filed in response to PUB/MH-I-84 identifies failed assets in the Manitoba Hydro electric system under the following risk categories:

D. Infrastructure

D1. Loss of Plant (high consequence)

D1.1 Water Retaining Structure and Flow Control (high consequence)

D3. Prolonged Loss of System Supply (high consequence)

D4. System Shutdown (Short Term) (medium consequence)

E. Human

E1. Safety and Health (medium-high consequence)

H. Governance/Regulatory/Legal

H5. NERC/MRO Reliability Standards (medium – high consequence)

As noted in COALITION/MH-I-93a, infrastructure failure is considered a significant risk facing the Corporation and that the renewal and replacement of aging infrastructure is a key measure to manage and mitigate this risk.

While Manitoba Hydro's risk management process guides the overall Corporate Risk Management Program, business units are ultimately responsible to manage risk within their areas of accountability. As such, each area manages its risks tailored to their specific methods of evaluation. The risk profiles, relative weights and criteria are also distinct in each area with consideration to the business objectives of each business unit.

Pertinent considerations related to Manitoba Hydro's risk assessment of failed assets include cost of lost generation, consequential damage of running asset to failure, incremental replacement costs, ability to promptly restore/replace an asset, complexity of restoration effort, impact to public and employee safety, environmental and criticality to customers.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into the risk management process and the prioritization of capital funding…." See also Coalition 1-11.

QUESTION:

Please provide a copy of the company manual that specifies the risk management process at Manitoba Hydro.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's risk assessment process as it relates to a significant cost driver. Seeks more specifics than Coalition/MH 1-11.

RESPONSE:

Corporate Risk Management Program

The overall Corporate wide risk management program is outlined in the Corporate Risk Management Report filed under PUB/MH-I-84. Key highlights are as follows.

The Corporation has a relatively low tolerance for risk since it is a Crown-owned utility providing an essential and life-sustaining energy service to Manitobans. However, because Manitoba Hydro is also an important economic driver for the Province, some risks are necessary in order to take advantage of opportunities to maximize value for stakeholders. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of: identifying threats that affect the achievement of the

Corporation's mission and mandate; mitigating the consequences of negative occurrences; and taking advantage of opportunities to provide benefits to all stakeholders.

To achieve these program objectives and guide consistent identification, assessment and management of risks across the Corporation, the Corporation has adopted a Corporate Risk Management Framework. The framework consists of a six step Risk Management Process, Risk Rating Criteria and Risk Tolerance Rating Criteria. Risk profiles identify and assess each risk, and a Corporate Risk Map (page 20) illustrates the results of the residual risk assessment for all risks facing the Corporation. Finally, the report identifies and summarizes the most material risks facing the Corporation under the headings High Consequence Risks and Significant and Emerging Risks (pages 3 – 19). The response to PUB/MH-I-84, outlines the numerous and varied resources used by Manitoba Hydro to assess and manage risk – ranging from the Board of Directors, the Executive and other Committees, management and support staff, and outside experts.

While the above noted process guides the overall Corporate risk management program, it is important to note that accountable business areas are ultimately responsible to manage risk within their areas of accountability to approved tolerance levels, with strict adherence to all laws, regulations and industry best practices.

Of particular relevance to this information request with respect to capital expenditure justification is that a catastrophic infrastructure failure continues to be identified as the most significant risk facing the Corporation and its customers due to the potentially extreme impact to people, the environment and the Manitoba economy. Key measures to manage and mitigate this risk include major new generation and transmission projects and the renewal and replacement of aging infrastructure.

Section:	Tab 4 Appendix 4.2	Page No.:	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into the risk management process and the prioritization of capital funding…." See also Coalition 1-11.

QUESTION:

Identify, describe and provide and fully functioning copy of any risk assessment models utilized in electronic format with the formulae intact and explain in complete detail how these model(s) are used to select and prioritize sustaining capital expenditures.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's risk assessment process as it relates to a significant cost driver. Seeks more specifics than Coalition/MH 1-11.

RESPONSE:

Please see the response to COALITION/MH-I-11a, which describes the overall framework for the evaluation and prioritization of its capital expenditures that includes specific risk assessments that are made by the Corporation.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into the risk management process and the prioritization of capital funding…." See also Coalition 1-11.

QUESTION:

Identify and describe the Manitoba Hydro asset management model(s) and explain in complete detail how these model(s) are used to select and prioritize sustaining capital expenditures.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's risk assessment process as it relates to a significant cost driver. Seeks more specifics than Coalition/MH 1-11.

RESPONSE:

Manitoba Hydro's asset management processes and models are dependent on the nature of the asset category and the health of its assets is one of many considerations in how capital expenditures are prioritized. As described in the Condition Assessment Summary report, in addition to the health of the assets, the processes and models used to manage the assets is dependent on several factors including criticality to operations, cost of maintenance and the amount of time to replace upon failure of the asset. Some assets deemed critical to operations will be replaced in advance of anticipated failure while others less critical to overall system reliability which can be replaced in a relatively short time frame will be operated to failure and then subsequently replaced.

Manitoba Hydro's asset management/maintenance systems are described below, each of which provides information to aid in optimizing the allocation of capital funds.

Models and systems used to manage generation assets consist of a computerized asset maintenance system and an asset investment system (AIP). The maintenance system is used to coordinate day to day maintenance activities to extend the life of these assets. The AIP system is used to forecast and prioritize large capital replacements. For long term planning, the AIP system uses an economic replacement model, based on the condition of the asset's health and the net present value of both risk(s) and replacement costs to forecast an economic replacement date. In the short term (5 years or less) all aging capital replacements are prioritized using project value, which includes all costs of deferral, including probability of failure and outage costs.

Transmission assets are subject to North American Electric Reliability Corporation (NERC) reliability standards and uses a computerized maintenance management system to coordinate the collection of asset condition data through routine tests and inspections. The transmission asset condition assessment methodology is then used to translate these inputs to an asset health index indicative of likelihood of failure. Long term system planning studies are performed using computerized power system simulation models to assess the impact of load growth and identify system enhancements required to ensure ongoing compliance. Also considered is the readiness to complete a project, the dependency between projects having to be completed in a particular sequence, and the options available to continue with the safe and reliable operation of the transmission system to meet load while awaiting a capital addition or replacement.

Distribution assets are typically low value, high volume with minimal options for maintenance to extend service life unlike generators, high voltage transformers, etc. The Distribution Maintenance Planning System (DMPS) is used as an asset registry for many of the asset classes. Asset assessment condition information to establish asset health, inspection cycles and physical properties are entered into the database for planning purposes. For the various asset classes where limited data is available, estimates are developed on future asset conditions. These estimates are incorporated into the capital planning and prioritization process.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into the risk management process and the prioritization of capital funding…." See also Coalition 1-11.

QUESTION:

Identify and describe the Manitoba Hydro work order management system and explain in complete detail how the system is used to select and prioritize sustaining capital expenditures.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's risk assessment process as it relates to a significant cost driver. Seeks more specifics than Coalition/MH 1-11.

RESPONSE:

Manitoba Hydro's work order management systems are not used to prioritize capital investment. These systems are used to schedule the procurement of material and resources for approved capital and maintenance projects.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into the risk management process and the prioritization of capital funding…." See also Coalition 1-11.

QUESTION:

Describe the process that Manitoba Hydro uses to prioritize projects within assets classes, and provide a fully functioning electronic copy of any model used in this process.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's risk assessment process as it relates to a significant cost driver. Seeks more specifics than Coalition/MH 1-11.

RESPONSE:

Please refer to COALITION/MH-I-11a for a description of Manitoba Hydro's capital prioritization processes.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 8
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Health Index		
Issue:	Asset Health Index prioritization process		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how Manitoba Hydro prioritizes the replacement between two assets within an asset class that have the same AHI score.

b) Please explain how Manitoba Hydro would prioritize the replacement between two station class transformers that have the same AHI score. Provide an example in the proposed CEF14 where Manitoba Hydro applies this process.

c) Please explain how Manitoba Hydro would prioritize the replacement between two wood poles that have the same AHI score. Provide an example in the proposed CEF14 where Manitoba Hydro applies this process.

d) Please explain how Manitoba Hydro would prioritize the replacement between two manholes that have the same AHI score. Provide an example in the proposed CEF14 where Manitoba Hydro applies this process.

RATIONALE FOR QUESTION:

Identify prioritization process of two assets within a class with the same AHI score.

RESPONSE:

The following is a response to parts a), b), c) and d).

a) A description of the capital expenditure prioritization process followed by Manitoba Hydro is found in the response to COALITION/MH-I-11a.

As noted in that response, Manitoba Hydro evaluates projects against a common set of risk criteria with consideration for asset condition and the maximization of economic value. Therefore, asset health, or the AHI score, is just one of many inputs in determining the project value.

For two assets having the same AHI score, the proposed project that provides the greatest overall project value and/or risk reduction would be receive a higher priority and its replacement would be scheduled sooner.

b) Manitoba Hydro would evaluate the replacement decision between two station transformers, assuming they have the same or similar AHI scores, on the basis of the overall risk profile associated with each of the two transformers currently in service. The asset health is only one consideration in this evaluation.

A evaluation of the criticality of each transformer is made against the risk criteria of system reliability, safety, efficiency, customer service, environmental impact and corporate profitability. In addition, local or situation specific circumstances would be taken into consideration in the evaluation. The respective loading of each transformer, and the forecast demands from increased customer load may be specific to each situation and may be an important factor in determining which of the two projects receive the higher priority.

c) Manitoba Hydro would evaluate the replacement decision between various wood poles of the same AHI score in a manner that is appropriate for an asset category that has over one million discrete assets. Given the large number of wood poles in service, wood pole replacement programs are designed and prioritized to manage overall risk and maintain customer service levels. Such projects may be specific to certain geographic regions of Manitoba Hydro's service territory and would be evaluated with consideration to public and employee safety, line performance, the type of circuit and number of customers served, and geographic considerations such as the relative remoteness of the assets in question.

This type of replacement program would be included in the Base Capital amounts identified and discussed on Page 31 in CEF14.

d) Manitoba Hydro would prioritize the replacement of manholes in accordance with an assessment of the specific type of manhole, the location of that manhole, the number of cables and cable voltages specific to that manhole, the number and type of customers served from that manhole, and the loading of the respective feeders involved. In addition, a comprehensive assessment would be completed on each manhole to evaluate the structural integrity of each vault based on factors designed to reduce risk. Prior to any final evaluation, an engineer will inspect the vault and provide a recommendation to either replace the manhole, reinforce or modify the structure, or defer action until it is deemed to be needed.

This type of replacement would be included in the Base Capital amounts identified and discussed on Page 31 in CEF14.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's budgeting process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into . . . the prioritization of capital funding…."

QUESTION:

Please provide a copy of the company manual that specifies the capital funding prioritization process at Manitoba Hydro.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's budgeting process.

RESPONSE:

Please see the response to COALITION/MH-I-11a.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's budgeting process		

PREAMBLE TO IR (IF ANY):

The Objectives of the Electric AHI Summary Report section includes the following: "Asset condition is an important input into . . . the prioritization of capital funding…."

QUESTION:

Describe the process that Manitoba Hydro uses to prioritize funding for asset classes and for projects within assets classes, and provide a fully functioning electronic copy of any model used in this process.

RATIONALE FOR QUESTION:

Review Manitoba Hydro's budgeting process.

RESPONSE:

Please refer to the response to COALITION/MH-I-11a.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 8
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Health Index Summary graphs		
Issue:	Assess scoring breakdown		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following:

Company manuals or guidelines that denote how Manitoba Hydro developed the scoring breakdown.

RATIONALE FOR QUESTION:

Assess scoring breakdown of a significant driver of hydro costs.

RESPONSE:

The scoring methodology used to classify each asset class from "Very Good" to "Very Poor" utilizes a number of unique criteria for each of the 29 asset classes identified in the Electrical Infrastructure Condition Asset Summary.

Manitoba Hydro's methodology determines Asset Health (AH) by performing standardized equipment condition assessments as part of the maintenance program. Technical experts take the condition assessment and factor in feedback from operations staff in conjunction with the asset's age, performance, tests/ inspection data, statistical failure models, historical data and other information to calculate the AHI score applied to the asset. For example:

- Generators are classified using historical testing data (high direct voltage ramp). In addition factors such as age, neighboring unit condition, and overhaul history were used to create the condition scores and replacement dates.
- The condition assessment for HVDC system converter transformers utilizes a number of factors including: oil samples (review of dielectric strength, moisture and combustible gas generation); power factor (review of capacitance bridge tests and excitation current); winding DC resistance (considers the test results from resistance tests, turn to turn ratio test and Swept Frequency Response Analysis tests); operation and maintenance (review of outages, maintenance history, and a corresponding reduction in score for failures); internal inspections of units (looking for core shifting, missing blocks); external inspections (looking for weld cracks, leaks, and cracked porcelain) and age of the unit.
- The assessment of distribution wood poles is based upon the integrated pole maintenance program inspection/evaluations, regularly scheduled visual inspections and age.

The condition of an asset will transition from one scoring level to another based on the availability of new data including condition assessment reports, previously experienced failures (from either Manitoba Hydro or other utilities), industry reports, increased age of the asset and estimates.

For a complete breakdown of the criteria used to score the health of each of the 29 asset classes see Appendix B, C & D of the Electrical Infrastructure Condition Asset Summary, filed as Appendix 4.2.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 8
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Health Index Summary graphs		
Issue:	Assess scoring breakdown		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following:

Company manuals or guidelines that describes how Manitoba Hydro replaces assets based on risk is affected by economic end of life assessments as it is denoted at the end of the scoring breakdown section.

RATIONALE FOR QUESTION:

Assess scoring breakdown of a significant driver of hydro costs.

RESPONSE:

On page 9 of Appendix 4.2, the report states "Some assets are replaced based on risk informed economic end of life assessments in conjunction with asset condition score." This statement relates to the prioritization of projects for capital investment purposes, which is described in the response to COALITION/MH-I-11a.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 8
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Health Index Summary graphs		
Issue:	Assess scoring breakdown		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following:

How do assets move from one scoring level to the next and when does Manitoba Hydro make that determination?

RATIONALE FOR QUESTION:

Assess scoring breakdown of a significant driver of hydro costs.

RESPONSE:

Please see the response to COALITION/MH-I-96a.

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 8
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset Health Index Summary graphs		
Issue:	Assess scoring breakdown		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the following:

Does Manitoba Hydro use a system other than the Asset Health Index Scoring to assign the condition rating for an asset class member? If so, please explain how that system works.

RATIONALE FOR QUESTION:

Assess scoring breakdown of a significant driver of hydro costs.

RESPONSE:

The condition score or rating used by Manitoba Hydro is discussed in the response to COALITION/MH-I-96a.

Please see the response to COALITION/MH-I-11a for information on how Manitoba Hydro prioritizes capital.

Section:	Tab 4 Appendix 4.2	Page No.:	p. 70
Topic:	Capital Expenditure Forecast		
Subtopic:	Current vs. 20 year Forecast of Asset condition		
Issue:	Comparison between current and forecast		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims that the charts used on section 5 of the Electric Asset Health Index Summary Report are arranged so the reader can compare the current condition of all assets versus the forecasted condition 20 years in the future. The transmission forecast includes approved capital sustainment programs for breakers, transformers and wood poles.

QUESTION:

Please indicate the amount of replacements for generation, transmission, HVDC and distribution by year as they are included in the 20 year forecast in electronic format.

RATIONALE FOR QUESTION:

To provide insight into the prioritization process and test reasonableness.

RESPONSE:

Please see the response to COALITION/MH-I-89a.

Section:	Tab 4 Appendix 4.2	Page No.:	p. 70
Topic:	Capital Expenditure Forecast		
Subtopic:	Current vs. 20 year Forecast of Asset condition		
Issue:	Comparison between current and forecast		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims that the charts used on section 5 of the Electric Asset Health Index Summary Report are arranged so the reader can compare the current condition of all assets versus the forecasted condition 20 years in the future. The transmission forecast includes approved capital sustainment programs for breakers, transformers and wood poles.

QUESTION:

Please provide a list with all the programs – capital sustainment or other- included in the 20 year forecast charts in electronic format and a breakdown of their cost and asset replacements amount by year.

RATIONALE FOR QUESTION:

To provide insight into the prioritization process and test reasonableness.

RESPONSE:

Manitoba Hydro undertakes numerous programs, on an annual basis, that facilitate the replacement or rehabilitation of various assets. Examples of these programs are listed below.

The level of capital funding allocated to each program within each asset category will vary in magnitude from year-to-year as established by a determination of the relative risk.

The quantity of assets in each asset category that are estimated to be replaced over the next 20 years will also change based on updates to asset condition and the evaluation of the relative risk between various assets. Please refer to COALITION/MH-I-89a for Manitoba Hydro's current projections of asset replacement quantities over the next 20 years.

Asset Replacement Programs:

- Stator Rewind and Replacement Program
- Transformer Replacement and Spares Program
- Breaker Replacement Program
- Exciter Replacement Program
- Protection Replacement Program
- Governor Replacement Program
- Turbine Overhauls (Hydraulic and Gas) Program
- Controls Equipment Replacement Program
- Upgrades to Dams and Spillway Structures
- Roofing Replacement Program
- Transmission Breakers Sustainment
- Transmission Transformer Sustainment
- Transmission Wood Pole Structure Sustainment
- Station Battery Bank Replacement Program
- HVDC Transformer Replacement Program
- Transmission Line Protection & Tele-protection Replacement Program
- Wireline Protection Replacement Program
- 13.2kV Shunt Reactors Replacement Program
- Bipole I&II Spacer Damper Replacement Program
- Integrated Pole Management Program.
- Emergency Pole Replacement Program.
- Insulator Replacement Program
- Ohio Brass (Insulators) Replacement Program
- Street Light Base Replacement Program
- Street Light Standard Replacement Program
- Street Light Cathodic Protection Installation Program
- Ground Rod Addition Program
- Underground Cable Rehabilitation Program
- Line Refurbishment Program
- Manhole Refurbishment Program

Section:	Tab 4 Appendix 4.2	**Page No.:**	p. 70
Topic:	Capital Expenditure Forecast		
Subtopic:	Current vs. 20 year Forecast of Asset condition		
Issue:	Comparison between current and forecast		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims that the charts used on section 5 of the Electric Asset Health Index Summary Report are arranged so the reader can compare the current condition of all assets versus the forecasted condition 20 years in the future. The transmission forecast includes approved capital sustainment programs for breakers, transformers and wood poles.

QUESTION:

Please provide an updated 20 year asset condition assessment forecast -similarly to the charts provided- in electronic format with the formulae intact assuming current replacement rates for generation, transmission, HVDC and distribution.

RATIONALE FOR QUESTION:

To provide insight into the prioritization process and test reasonableness.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-89b.

Section:	Tab 4 Appendix 4.2	Page No.:	p. 70
Topic:	Capital Expenditure Forecast		
Subtopic:	Current vs. 20 year Forecast of Asset condition		
Issue:	Comparison between current and forecast		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims that the charts used on section 5 of the Electric Asset Health Index Summary Report are arranged so the reader can compare the current condition of all assets versus the forecasted condition 20 years in the future. The transmission forecast includes approved capital sustainment programs for breakers, transformers and wood poles.

QUESTION:

Please provide updated 20 year asset condition assessment forecast in electronic format - similarly to the charts provided- with the formulae intact assuming proposed replacement rates for generation, transmission, HVDC and distribution.

RATIONALE FOR QUESTION:

To provide insight into the prioritization process and test reasonableness.

RESPONSE:

Manitoba Hydro does not replace assets on a replacement rate basis and therefore, proposed replacement rates are not available. All aging asset replacements are planned and prioritized to manage risk (please see the response to COALITION/MH-I-11a.

Section:	Tab 4 Appendix 4.2, Appendix B	**Page No.:**	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt "Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI."

QUESTION:

Please provide Company manuals or guidelines that describe how the technical experts should evaluate the condition assessment and other inputs to calculate the AHI.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

Manitoba Hydro performs condition assessment on its generation assets by utilizing the hydroAMP condition assessment methodology. Condition assessment results are then input into CopperLeaf decision support software. CopperLeaf is used for generation asset management and capital investment planning.

HydroAMP provides condition assessment guidelines and protocols which form the basis for the data collection and analysis processes to be followed. Manitoba Hydro has enhanced and modified the basic hydroAMP methodology with consideration to the specific requirements and characteristics of Manitoba Hydro's operations and with regard to improving upon the overall assessment approach.

The guidelines provided by hydroAMP for its condition assessment methodology are found at the following link:

http://operations.usace.army.mil/bmp.cfm?CoP=hydro

Section:	Tab 4 Appendix 4.2, Appendix B	**Page No.:**	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt "Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI."

QUESTION:

Provide a copy of the company's job description for the technical expert from the human resources department.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

The quote in the preamble is a verbal description of the condition assessment methodology referred to in the response to COALITION/MH-I-96a.

The reference from Appendix B refers to subject matter experts. Senior engineering staff directed the selection and further development of the asset condition assessment tools. These same senior engineers supervised the collection of relevant information and the scoring of the condition of the assets.

At the beginning of the process, teams of subject matter experts from different departments were created for each asset type. These teams reviewed possible alternative tools for assessing the condition of their asset type, transformers for example. This process ultimately lead to teams choosing to use HydroAMP condition assessment methodology or modifying HydroAMP, or in the case of turbines, developing their own condition assessment tool.

Given the diverse set of assets, many subject matter experts, with decades of engineering experience, took part in the asset condition assessments. See Coalition/MH I-98d for job titles of many of those involved in leading the condition assessment effort. The following gives an example of the typical roles and responsibilities of asset type subject matter experts who are senior engineers.

Typical Roles and Responsibilities of Asset Type Subject Matter Experts

- Sit on Asset Type Advisory Teams to provide technical review of significant Capital Project Justifications (CPJs) and data inputs for CopperLeaf C55.
- Perform or supervise staff performing condition assessments on assigned assets types
- Provide engineering support to station staff to deal with operating and maintenance problems of hydraulic and thermal generating stations.
- Investigate generating equipment deficiencies or problems and determine scope of corrective work. Conduct root cause analysis on station equipment and systems.
- Take the role of project owner or project manager and deliver quality projects on time. Prepare specifications, analysis of tenders and recommendation for purchase of equipment and services.
- Coordinate required design work with staff, consultants or the appropriate design departments and ensure that the completed project meets the ongoing requirements of generating stations.
- Lead or participate in field testing programs and equipment commissioning as required.
- Participate in the planning, scheduling and implementation of maintenance programs for all electrical equipment and controls systems associated with the generating stations.
- Prepare CPJs and make presentations as required.
- Prepare technical reports, commissioning procedures, and field inspection reports as required.
- Supervise technical staff and provide functional supervision to field staff in hydraulic and thermal generating stations.
- Make frequent field trips to all Generation South generating stations for either routine planned work or to provide emergency response to outages, river control, safety or environment concerns.
- Keep abreast of new developments in assigned asset types.

Typical Roles and Responsibilities of the Capital Planner

- Use knowledge of operation, maintenance and/or design of generating stations to lead cross functional teams to create a strategically important database of future (up to 20 years) projects.
- Use specialized engineering knowledge to lead engineering and station staff teams to perform strategically important condition assessments on major components on all generation north and south generating units to assess health condition rankings.
- Lead development, training, and implementation of Copperleaf C55 processes to produce a sustainable long term capital plan.
- Lead process change involving Division Managers, Manager and Section Heads so that the condition assessments and long term planning process is update by stakeholders in various Generation Operations departments to ensure that candidate items in the Portfolio Management System are supported by performance date, equipment health, revenues, etc.
- Coordinate the work of consultants and internal IT specialists to gather data from Manitoba Hydro systems (AMPS, Generating Stations, Design Departments, Insulation Testing, Generation Maintenance Engineer, and Technical Services) to establish the current overall health of main plant systems or components.
- Interface with various stakeholders in capital planning, including maintenance engineering, design engineering, project management, plant management and finance.
- Work with Maintenance Engineering Section Heads to schedule and submit Capital Project Justifications for all major work required.
- Liaise with Capital Planning Engineers from other utilities to share methods and experiences.

Section:	Tab 4 Appendix 4.2, Appendix B	**Page No.:**	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt “Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset’s age, life curve, and performance to calculate the AHI.”

QUESTION:

Describe what training technical experts receive prior to participating in the AHI process.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

As noted in the response to COALITION/MH-I-98b, senior engineering staff directed teams of staff in the selection and further development of the asset condition assessment tools.

During this process all of the teams developed a good understanding and knowledge of the condition assessment tools and certain team members acted as the trainers of others when required.

Section:	Tab 4 Appendix 4.2, Appendix B	Page No.:	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt "Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI."

QUESTION:

Identify by job title the technical experts involve in creating the current AHI.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

Staff titles involved in the creating the Asset Health Index for generation assets are shown below. Many of the staff in these positions either executed the methodologies to assess asset conditions or supervised other staff doing same.

Transformers and Breakers:

- Insulation Engineering & Testing – Generation & T&D Technical Officer
- Generation Maintenance Engineering – Apparatus Group Team Leader
- Generation Maintenance Engineering – Apparatus Group Technical Officer
- Generation Maintenance Engineering – Generation Performance Group Team Leader

Turbines:

- GME Mechanical Section – Predictive Programs Team Leader
- GME Mechanical Section – Predictive Programs Technical Officer

Generators:

- Insulation Engineering & Testing – Generation & T&D Technical Officer
- Generation Maintenance Engineering – Generation Performance Group Team Leader

Governor and Exciter

- Generator Performance Team Leader
- Operations Support Engineer
- NERC Project Engineer
- Control Engineer

Batteries

- Generator Performance Team Leader
- Generator Maintenance Engineer

Section:	Tab 4 Appendix 4.2, Appendix B	**Page No.:**	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt "Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI."

QUESTION:

Please list all scoring criteria that are used in this process and describe how each factor is weighed.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

Please see the response to COALITION/MH-I-98a for a link to the HydroAMP guidelines where weightings are discussed.

Section:	Tab 4 Appendix 4.2, Appendix B	**Page No.:**	p. 81
Topic:	Capital Expenditure Forecast		
Subtopic:	Generation Operations		
Issue:	Assess condition assessment methodology		

PREAMBLE TO IR (IF ANY):

Appendix B of the Electric Asset Health Index Summary Report includes the following excerpt "Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI."

QUESTION:

Please prove a list of the top 100 projects with the worst AHI scores and identify which projects are scheduled for replacement in 2015.

RATIONALE FOR QUESTION:

Ensure repeatability of process and documentation are established by Manitoba Hydro.

RESPONSE:

The table below outlines all of the generation assets in very poor condition in 2015. The column on the left lists the investments (projects) planned to correct the condition and the columns on the right are the total count.

All assets whose failure could cause a prolonged unit outage such as transformers, exciters, governors and stators are covered by planned projects. Projects indicated in red in the table represent assets that are in very poor condition that did not have an investment planned in the CEF13 Budget. All of these assets are breakers that are in operation with no Lost Generation Risk associated with them. Many of them have redundancy, which minimizes the impacts of failure. Replacement of these assets is also often a smaller investment and can be planned for in a shorter period of time.

Planned Investments Impacting Asset In Very Poor Conditon	ASSET TYPE										Total Assets in Very Poor Condition (2015)	Very Poor Assets with No Planned Investment
	Battery, Banks	Breaker, Generator	Breaker, Station Service	Breaker, Switchyard	Excitation System, Mechanical	Generator, Stator	Governor, Analog	Governor, Digital	Transformer, GSU	Turbine, Hydraulic		
Grand Rapids												
GRAND RAPIDS UNIT TRANSFORMERS REPL									1		1	0
Great Falls												
GF BNK 6 & SPARE GEN STEP UP TRANSFORMER									2		8	2
GF EXCITATION SYS UPGRADE -UNITS 1,2,5,6					1							
GREAT FALLS GS- UNIT #4 MAJOR OVERHAUL									3			
No Planned Investment			2									
Jenpeg												
JPG FIRE DAMAGE REHABILITATION	1						1				3	0
JPG UNIT 4 RESTORING ROD REFURBISHMENT										1		
Limestone												
LIMESTONE GOVERNOR CONTROL REPLACEMENT								10			10	0
Pine Falls												
PINE FALLS 115KV BREAKER REPLACEMENT				10							10	0
Pointe du Bois												
No Planned Investment		8	2	16							44	26
PDB Emergency Capital Unit Repairs										1		
POINTE DU BOIS GS REHABILITATION		6	1	5						5		
Selkirk												
No Planned Investment				8								8
Seven Sisters												
No Planned Investment			9								10	9
SS TRANSFORMER BANKS 5 & 6 REPLACEMENT									1			
Slave Falls												
SF MAJOR OVERHAULS UNITS 3-8				4	1	1			3	2	11	0
										Sum	97	45

Section:	Tab 4 Appendix 4.2, Appendix C	Page No.:	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

Appendix C refers to a third part consultant which worked with various Manitoba Hydro departments in developing asset condition assessment methodologies and statistical failure models for transmission elements.

QUESTION:

Please provide a copy of the engagement letter and project scope (including any revisions) of the third party consultant with Manitoba Hydro regarding the developed model or models.

RATIONALE FOR QUESTION:

Asset condition assessment methodology review and analysis is a central element in testing reasonableness of expenditure.

RESPONSE:

Please see the attached Consulting Agreement and Amending Agreement between Manitoba Hydro and Kinectrics Inc. to develop and implement methodologies for asset condition assessment, asset risk assessment and optimal asset management and investment planning, specifically for transformers, breakers and transmission lines.

At the specific request of Kinectrics, the pricing information has been redacted due to its commercially sensitive and competitive nature.

CONSULTING SERVICES AGREEMENT

THIS AGREEMENT effective as of January 16, 2012.

BETWEEN:

MANITOBA HYDRO

of the first part,

- and -

KINECTRICS INC.

of the second part.

(the "Consultant")

IN CONSIDERATION OF the sum of ten ($10.00) dollars and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree as follows:

1 INTERPRETATION

1.1 In this Agreement, unless the content or subject matter indicates otherwise, the following terms shall have the following meanings:

"Agreement" means this agreement and Schedule "A", and it is mutually agreed that each of the said documents forming part of the Agreement are incorporated by reference therein with the same effect as if at length set forth therein. All the terms, conditions, provisions and requirements of this agreement and Schedule "A" shall apply to and have effect in connection with the Agreement provided, that in the event of any inconsistency between any of the said documents, the order of application of same for the purpose of the interpretation and application of the Agreement shall be as follows:

(a) this agreement; and
(b) Schedule "A".

All of the terms, conditions, provisions and requirements of the documents referred to above shall apply to and have effect in connection with the Agreement as if the said documents and the Agreement were contained in the one instrument.

"Background Intellectual Property" means any information, knowledge, means or method that is owned by a party or a third party and used by a party prior to the Effective Date of the Agreement including, copyright, discoveries (patented or otherwise), software, data (hard copies and machine readable) or processes, conceived, designed, written, produced, developed or reduced to practice, all patents, trademarks, copyrights and industrial designs arising therefrom, including any new or useful improvements thereto.

"Business Day" means 08:00 hours to 16:30 hours of any day other than Saturday, Sunday or any statutory or civic holiday observed in the Province of Manitoba.

"Confidential Information" means all information concerning Hydro and the Services that is supplied by Hydro or otherwise comes into the possession of Consultant during the course of performance of the Services, regardless of format or medium, and the Service Product. Confidential Information does not include:

(a) information that is generally known to the public through no fault of Consultant;
(b) information that was specifically known to Consultant before disclosure by Hydro and was not subject to a confidentiality obligation;
(c) information from a source other than Hydro so long as such source was not subject to a confidentiality obligation; and
(d) information that is subpoenaed or ordered to be disclosed by a judicial or regulatory body of competent jurisdiction.

"Consultant" means the Person named above and the permitted legal personal representatives, successors and assigns of the Consultant.

"Effective Date" means the day and date first written above.

"Hydro" means Manitoba Hydro.

"Person" and **"person"** shall be broadly interpreted to include, without limitation, any corporation, partnership, other entity, or individual.

"Purchase Order" means a document entitled Purchase Order issued by Hydro to the Consultant.

"Term" has the meaning given in Section 2.1 hereof.

"Services" means the various work and services to be done, executed, provided, delivered and/or performed by the Consultant described in the Agreement, and includes, without limitation, the work and services described in Schedule "A" Terms of Reference, and the provision of all personnel, labour, equipment, apparatus, machinery, and materials to be furnished and/or supplied by the Consultant necessary in the performance of same.

"Service Product" means all deliverables described in Schedule "A" Terms of Reference and otherwise under the Agreement, and all products arising from the Services, regardless of form, format, or medium, including, without limitation, information, know-how, drawings, designs, reports, products, processes, documents, research notes, data, photographs, maps, materials, work in progress, and other tangible or intangible property, and all intellectual property rights thereto.

1.2 Attached to and forming an integral part of the Agreement are the following appendices:

Schedule "A" Terms of Reference

1.3 The recitals hereof form an integral part of the Agreement.

2 TERM

2.1 The term of the Agreement shall commence as at the Effective Date and shall, subject to earlier termination, continue in force and effect until January 16, 2013, (the "Term").

2.2 Nothing in the Agreement prevents Hydro from contracting with any other Person for the purchase of any work or services, including any work and services the same as that which is contemplated in the Agreement, or the same as any Services.

3 SERVICES

3.1 Consultant shall perform the Services.

3.2 Consultant shall:

(a) perform its obligations in a timely manner;
(b) perform its obligations in a good, workmanlike and professional manner;
(c) use due care in the performance of its obligations to ensure that no person is injured or killed, no property is damaged or lost, and no rights are infringed;
(d) provide written reports (in addition to any specified in Schedule "A") with respect to the Services at Hydro's request;
(e) comply with all reasonable instructions and requests made by Hydro concerning the Services and the Agreement;
(f) comply with all applicable federal, provincial, municipal, state, or other laws, by-laws, and regulations; and
(g) comply with Hydro's corporate policies and procedures which have been provided by Hydro to Consultant.

3.3 Consultant shall perform the Services in accordance with this Agreement and all Schedules attached hereto.

4 PAYMENTS

4.1 Fees and charges for performance of the Services are described in the Schedule "A" Terms of Reference.

4.2 If pre-approved by Hydro, Consultant's reasonable expenses incurred in performance of the Services will be reimbursed, at actual cost.

4.3 Consultant shall provide itemized invoices to Hydro on a monthly basis. Hydro's Purchase Order number shall be referenced on the face of each invoice. Taxes payable shall be shown as separate line items on each invoice. All invoices shall be satisfactory to Hydro in form and content. Consultant shall deliver to Hydro any supporting documents and receipts requested by Hydro from time to time.

4.4 Hydro shall pay Consultant all undisputed compensation due within 30 days following receipt of an invoice and supporting materials pursuant to Section 4.3 hereof. Amounts shall be calculated and paid in Canadian dollars unless otherwise stated in Schedule "A".

4.5 Consultant may charge interest on overdue accounts, at the annual interest rate of 1.5% above the prime lending rate established by the Royal Bank of Canada, in effect at the time the amount initially became due, calculated and payable monthly. The same applies to the disputed portion of an invoice subsequently found be properly due and payable.

5 INDEPENDENT CONTRACTOR

5.1 Consultant is an independent contractor. The Agreement shall not be deemed to create the relationship of employer and employee, principal and agent, partnership, or joint venture between Hydro and Consultant.

5.2 Consultant is responsible for any deductions or remittances required by law.

5.3 Consultant has no authority to make any representation, enter any commitment, or incur any liability on behalf of Hydro, except with the prior written consent of Hydro.

6 APPROVAL OF PERSONNEL AND NON-ASSIGNMENT

6.1 Consultant shall perform the Services personally or using an employee or subcontractor listed in Consultant's Proposal. Consultant shall not engage any other employee or subcontractor in performance of the Services without the prior written consent of Hydro.

6.2 At Hydro's request, Consultant shall cease using an employee or subcontractor for any reasonable cause including unsatisfactory performance, failure to pass a personnel risk assessment to Hydro's satisfaction, or failure to comply with Hydro policies or procedures.

6.3 Consultant shall not assign or transfer the Agreement or any of its rights or obligations under the Agreement, without the prior written consent of Hydro.

7 OWNERSHIP OF SERVICE PRODUCT

7.1 The Service Product is the exclusive property of Hydro upon creation. Consultant hereby waives any moral rights to Service Product and at Hydro's request shall obtain waivers of moral rights. Consultant shall make no use of the Service Product other than to provide the Services, except with the prior written consent of Hydro.

7.2 At Hydro's request, Consultant shall deliver to Hydro the Service Product and a record of all Service Product.

7.3 Consultant owns the entire right, title and interest to its own Background Intellectual Property, including any new and useful improvements thereto and its means and methods. To the extent Background Intellectual Property is incorporated or included in any Service Product, Consultant hereby grants to Hydro the right and license to copy and use such Background Intellectual Property for Hydro's business purposes.

8 CONFIDENTIALITY

8.1 Consultant may only use Confidential Information for the purpose of providing the Services to Hydro. Consultant shall not use Confidential Information for any other purpose.

8.2 Consultant may share Confidential Information with an employee or subcontractor who has a need to know for the purpose of the Services. Consultant shall be responsible for any violation of Section 8 hereof by such persons. Consultant shall not disclose Confidential Information to any other person without Hydro's prior written consent.

8.3 At Hydro's request, Consultant shall immediately return Confidential Information to Hydro, or certify in writing that it has been destroyed.

8.4 Consultant acknowledges that any failure to comply with the provisions of Section 8 hereof shall cause irreparable harm to Hydro which cannot be adequately compensated by damages. Accordingly, in addition to any other remedies available to it, Hydro shall be entitled to interlocutory and permanent injunctive relief to restrain any anticipated, present, or continuing breach of Section 8 hereof.

9 PROTECTIONS

9.1 Consultant shall:

(a) secure all of its premises, equipment and storage cabinets used in connection with the Services, against damage and unauthorized access;
(b) safeguard all electronic data used in connection with the Services including its use, access, transfer and storage, against damage and unauthorized access;
(c) immediately notify Hydro of the discovery of any damage or unauthorized access, and any threats or attempts to accomplish the same.

9.2 At Hydro's direction, Consultant and any of its employees or subcontractors engaged in performance of the Services shall undergo a personnel risk assessment.

9.3 Consultant shall take all measures required by law to protect personal information pursuant to The Freedom of Information and Protection of Privacy Act (Manitoba) and the Personal Information Protection and Electronic Documents Act (Canada). The provisions of Sections 8 and 9 hereof apply to all such personal information, with necessary modification.

9.4 When on Hydro premises, Consultant shall comply with Hydro safety and security policies.

10 LIABILITY AND INDEMNIFICATION

10.1 Consultant shall indemnify and save harmless Hydro, and its directors, officers, and employees, from and against any and all actions, causes, losses, costs, damages, expenses, suits, claims, liabilities, debts, and demands which they may suffer or be put to, arising from Consultant's breach of the Agreement or the negligence or wilful misconduct of Consultant.

10.2 The aggregate liability of Consultant and its officers, directors and employees to Hydro under the Agreement, whether in contract or tort, shall be limited to: (a) $1,000,000.00, or (b) the total amount of compensation payable by Hydro to Consultant under the Agreement, whichever is greater. The forgoing limitation shall not apply in any case of gross negligence, intentional misconduct or reckless conduct.

10.3 Neither party shall have any liability to the other for any indirect, incidental, or consequential damages.

10.4 Nothing in the Agreement shall be construed to relieve any insurer of its obligations to pay claims consistent with the provisions of a valid insurance policy.

11 INSURANCE

11.1 Consultant shall maintain comprehensive general liability insurance in the minimum amount of two million dollars per occurrence, for bodily injury, death, and damage to property including loss of use thereof. The policy shall include coverage for premises property and operations, products and completed operations, blanket contractual liability, cross liability, non-owned automobile liability and occurrence property damage. The policy shall be endorsed to provide Manitoba Hydro with not less than 30 days written notice in advance of cancellation and to show Manitoba Hydro as an additional insured.

11.2 Consultant shall maintain automobile liability insurance in the minimum amount of two million dollars, at its own cost, for licensed vehicles owned or operated by Consultant.

11.3 Upon request, Consultant shall provide certificates of insurance to Hydro.

11.4 Consultant shall pay any assessment or compensation required to be paid pursuant to The Workers Compensation Act (Manitoba). Upon failure to do so, Hydro may pay the assessment or compensation to the Compensation Board and deduct the amount from monies due to Consultant. Hydro may require a declaration from the Compensation Board that assessments or compensation have been paid in full, and may withhold payment to Consultant until the declaration is received.

12 SUSPENSION AND TERMINATION

12.1 Hydro may, for its convenience, delay or suspend Consultant's performance of any or all of the Services, by giving five (5) Business Days' notice to Consultant.

12.2 Hydro may, for its convenience, terminate the Agreement by giving 10 Business Days' notice to Consultant.

12.3 Consultant shall cease to perform the Services upon receipt of a notice pursuant to Section 12.1 or 12.2. At Hydro's request, Consultant shall resume performance of the Services as soon as reasonably possible following a delay or suspension.

12.4 Hydro shall compensate Consultant for direct costs and expenses actually incurred by Consultant that are directly attributable to a delay or suspension pursuant to Section 12.1 hereof, but not for lost profit.

12.5 Hydro shall compensate Consultant for direct costs and expenses actually incurred by Consultant that are directly attributable to a termination pursuant to Section 12.2 hereof, for Services performed to the date of termination, and for any reasonable expenses of Consultant necessary for winding down performance of the Services, but not for lost profit.

12.6 Without prejudice to any other of its rights or remedies, Hydro may immediately terminate the Agreement if Consultant is in breach of any term or condition of the Agreement, or if Consultant becomes bankrupt or insolvent.

12.7 The expiry or termination of the Agreement shall not affect or prejudice any rights or obligations that have accrued or arisen under the Agreement prior to the time of expiry or termination, and those rights and obligations shall survive such expiry or termination. Notwithstanding any other term or condition of the Agreement to the contrary, Sections 6.3, 7, 8, 9, 10, 12.5, 14, and 15 hereof and all other provisions of the Agreement necessary to give effect thereto, shall survive the expiry or termination of the Agreement.

13 FORCE MAJEURE

13.1 Neither party shall be in default of the Agreement where the failure to perform an obligation is due wholly to a cause beyond its reasonable control. The party experiencing such a difficulty shall promptly notify the other of its inability to perform its obligation. The parties agree to negotiate in good faith an extension of time for performing the obligation, avenues to resolve the situation and resolution of any financial impacts. Both parties shall mitigate their losses.

14 RECORDS AND AUDITS

14.1 Consultant shall maintain and preserve accurate and complete records in respect of the Services. During the term of the Agreement and for a period of five (5) years thereafter, upon reasonable notice, Consultant shall make such records available to Hydro, its agents and auditors, for inspection and copying during reasonable business hours.

15 GOVERNING LAW

15.1 The Agreement shall be subject to, interpreted, performed and enforced in accordance with the laws of Manitoba without regard to Manitoba or Canadian law governing conflicts of law, even if one or more of the parties to the Agreement may be resident of or domiciled in any other province or country. The parties hereby irrevocably attorn to the exclusive jurisdiction of the Court of Queen's Bench of Manitoba, Winnipeg.

16 NOTICES

16.1 Every notice required or permitted to be given pursuant to the Agreement shall be in writing, and shall be delivered personally or by fax:

To Hydro:	To Consultant:
Manitoba Hydro 820 Taylor Avenue (3) Winnipeg, MB, R3M 3T1	Kinectrics Inc. 800 Kipling Avenue, Unit 2 Toronto, Ontario M8Z 6C4
Fax: (204) 360-6149 Attn: Vice President, Transmission	Fax: (416) 237-9053 Attn: S. Zanganeh

In addition to forgoing, Hydro may effectually give notice to Consultant by giving same to Consultant's address and contact particulars included in the Purchase Order or any included in the Consultant's Proposal.

Notice given or served by personal service shall be deemed effectually given and received upon such personal service, and notice given or served by fax shall be deemed effectually given and received on the first (1st) Business Day after the day of transmission.

17 GENERAL

17.1 The Agreement is the entire agreement between the parties. There are no other undertakings, representations, or promises, express or implied. The division of the Agreement into Sections, Subsections, Divisions, Schedules, Appendices or other subdivisions, and the insertion of headings, are for convenience of reference only and do not affect the interpretation of the Agreement.

17.2 Each party shall, from time to time, take such actions and execute such documents as may be necessary to give effect to the Agreement.

17.3 If any provision in the Agreement is found to be unenforceable at law, it shall be deemed severed from the Agreement and the remaining provisions shall continue in effect.

17.4 No amendment of the Agreement is valid unless it is in writing, signed by both parties.

17.5 No extension of time for performance of the Services is valid unless it is in writing, signed by Hydro.

17.6 No waiver of any provision of the Agreement, or of a breach hereof, is valid unless it is in writing, signed by waiving party. Waiver of a breach is not a waiver of a subsequent breach.

17.7 The Agreement shall enure to the benefit of and be binding upon, the heirs, executors, administrators, successors and permitted assigns of the parties.

IN WITNESS WHEREOF the parties hereto have executed the Agreement as at the Effective Date.

MANITOBA HYDRO	**KINECTRICS INC.**
Per: ______________ Authorized Signing Officer	Per: ______________ Authorized Signing Officer
Per: ______________ Authorized Signing Officer	Per: ______________ Authorized Signing Officer

SCHEDULE "A"

TERMS OF REFERENCE

1 GENERAL

In the Agreement, the following terms shall have the following meanings:

"Asset Maintenance" means activities intended to extend the lifetime of an asset and keep the asset operating to a specified level of functioning. These activities include inspection, testing and repairing the asset when it makes economic sense to do so. Asset Maintenance can be broken down into Scheduled Maintenance, which is preventive or predictive maintenance tasks done as part of a planned maintenance program, and breakdown maintenance, which is unplanned maintenance to correct a breakdown.

"Breakdown" means an incident where an asset has a repairable defect.

"Economic End-of-Life" means the point in time at which expected costs, including risk costs and expected costs, of keeping an asset in service exceeds the cost of purchasing and installing a replacement asset.

"Failure" means an incident where the asset must be taken out of service and cannot be economically repaired and placed back into service (i.e. an end-of-life event).

2 APPENDICES

The following appendices are attached to and form an integral part of this Schedule "A" and the Agreement:

Appendix "A" Asset Information

Appendix "B" Cyber Security

3 BACKGROUND

Manitoba Hydro requires assistance to develop and implement methodologies for asset condition assessment, asset risk assessment and optimal asset management and investment planning, specifically for transformers, breakers and transmission lines currently in service on the Manitoba Hydro transmission system.

4 KINECTRICS PROJECT TEAM

The Kinectrics' Project Team shall consist of the following core of engineers who are experts in asset management and who are subject matter experts in the areas of specific studies to be performed in order to develop Asset Investment Strategies:

Project Team Member	Project Role & Estimated Time
Yury Tsimberg, B.A.SC, M. Eng. in E.E.	Project Team Leader
Stephen Cress, B.A. SC in E.E.	
Gary Ebersberger, B.Eng in E.E., MBA,	
Fan Wang, B.Eng, M. Eng, Ph.D in E.E.	
Katrina Lotho, B.E.SC in E.E.	

The above listed key personnel shall be made available for the duration of the Services. In addition, if the need arises, the Project Team shall be able to use expertise and knowledge of other resident experts at Kinectrics who are involved in developing standards, testing and validating emerging technologies, conducting certification and qualification testing for various components of power system, performing risk assessment and systems studies, or are experts in virtually every area of the power industry beyond the scope of this project.

5 MANITOBA HYDRO PROJECT LEAD

Manitoba Hydro will designate a Project Lead who will be the single point of contact responsible for facilitating information exchanges, conference calls, visits and meetings with Manitoba Hydro staff.

6 SERVICES PERFORMANCE TIMELINE

Hydro expects that the Services will be performed in accordance to the following estimated schedule:

DETAIL	DATE
Award of contract	January 2012
Commencement of Services	February 2012
Interim Report to Manitoba Hydro on methodologies	On or before July 31, 2012
Draft Final Report delivered to Manitoba Hydro	On or before August 15, 2012
Final Report delivered to Manitoba Hydro	On or before September 15, 2012
Services completed	September 30, 2012

6.1 Implementation Schedule

Within fourteen (14) days of the date of the Agreement, Kinectrics shall deliver to Manitoba Hydro, to the attention of Mr. Brent Jorowski, Manager, Transmission Asset Strategies Dept., Manitoba Hydro fax (204) 360-6174, or designate, a proposed schedule detailing all of the work and activities required for the performance and completion of the Services.

Kinectrics's proposed schedule shall be a detailed critical path method schedule for the Work. The schedule shall clearly depict and describe the timing, duration, sequences and interdependencies of all its activities in sufficient detail to satisfy Manitoba Hydro with regard to the planning of the Services.

Upon acceptance by Hydro, the proposed schedule (original or revised) shall not be modified, altered or revised without prior written approval from Hydro.

Kinectrics shall monitor the progress of the Services against the schedule and shall notify Manitoba Hydro in writing immediately upon becoming aware of any potential delay or factors that could cause delay in the performance of the Services, including any delay achieving any milestone and delivery date(s) for the Work, and shall indicate remedial steps Kinectrics is taking or intends to take to prevent such delay.

The schedule shall identify and include or make due allowance for the following:

(a) Start and completion dates.
(b) Milestone dates.
(c) All work and activities to be performed by Kinectrics (including all procurement, design, and testing activities, submission reports, hold points for inspection/witnessing).
(d) Work to be performed by subcontractors.
(e) Work and activities performed by Manitoba Hydro.
(f) Required submittals, delivery, review, and approval activities.
(g) Such other information as directed by Manitoba Hydro.

Kinectrics shall perform the Services within the limitations of the schedule which shall be reviewed and updated by Kinectrics every month, or at any time as may be required by either Hydro or Kinectrics.

6.2 Performance and Delivery

Kinectrics shall perform, deliver and execute all applicable Services in accordance with any agreed upon schedule(s).

Kinectrics shall commence, perform, execute and deliver all Services without interruption and in a prompt, timely, and continuous manner.

7 PROGRESS REPORTS

Kinectrics shall deliver to Hydro, on a monthly basis, progress reports detailing the status of the Services. Monthly progress reports shall include the following information (non-exhaustive):

(a) state of the project including any significant milestones reached;
(b) hours worked on the project during the previous month;
(c) cumulative hours;
(d) cost for the month,
(e) total project cost and the projected hours to complete the project;
(f) percent of work complete must be compared with percent budget spent; and
(g) other information requested by Hydro.

8 PERMITS

Kinectrics shall secure and maintain all permits, licenses, clearances and approvals now or hereafter required for the performance, delivery and execution of the Services and Kinectrics' obligations under the Agreement.

9 CYBER SECURITY

When directed by Hydro, and if deemed commercially reasonable by Kinectrics, Kinectrics shall, under and in respect of the Agreement, and in respect of the Services, including without limitation:

a) the activities, business practices, and procedures of Kinectrics in respect of, and involving, Kinectrics's performance of obligations under the Agreement, including performance of the Services; and

b) the Services and equipment and materials,

comply with the requirements of Appendix B Cyber Security.

10 SERVICES

The Services is all that is required for the development, documentation and application of methodologies for an aging asset management and investment plan for power transformers, breakers and transmission lines currently in-service on Manitoba Hydro's transmission system. In addition, the Services will include recommendations to improve Manitoba Hydro's ability to collect asset data, assess asset conditions and risk of asset failure, and to estimate the economic end of life for these assets.

The Services shall be completed in stages. At the end of each stage of the Services, the Purchaser will provide written approval to Kinectrics to proceed to a subsequent Stage of the Services. Manitoba Hydro may, at its discretion, decide not to proceed with one or more of these Stages.

Kinectrics shall carry out additional meetings and communications with Manitoba Hydro as required to successfully complete these Services. Kinectrics shall appoint a Project Leader who will act as the single point of contact for Manitoba Hydro. Manitoba Hydro will appoint a Project Leader who will act as the single point of contact for Kinectrics. These Project Leaders shall be accountable for facilitating and/or initiating information exchange, conference calls, interviews, visits, and meetings with Manitoba Hydro staff as required to successfully completing the Services.

10.1 Stage 1: Preliminary Services & Data Assessment

Kinectrics shall complete preliminary work as required to assess the asset data provided by Manitoba Hydro and develop asset class definitions which will guide the subsequent components of the Services.

These services will involve Kinectrics analyzing the initial available data/information provided by Manitoba Hydro, and consulting with Manitoba Hydro to define the Asset Categories and develop and confirm the optimal approaches and methodologies to employ to complete the Services based on the availability and quality of asset data/information.

Kinectrics shall provide Manitoba Hydro with asset data templates for the transformer, circuit breaker and transmission line assets to be assessed.

Kinectrics shall meet with Manitoba Hydro to define asset categories for transformers, circuit breakers and transmission lines based on factors such as voltage, usage, design, and functionality. At this meeting, Manitoba Hydro field staff will provide expert opinions to the Kinectrics regarding maintenance and operating practices, known problems with certain manufacturers or asset in specific geographic locations, dominant condition parameters in making end-of-life decisions and other information that is required to develop Manitoba Hydro's Health Index formulations. The means and method of transferring asset data/information between Manitoba Hydro and Kinectrics will also be determined at this meeting.

Kinectrics shall identify the condition and consequence parameters that will be useful in condition and risk assessment, which will include but not limited to, age, loading, manufacturer, maintenance records, outage history, and financial information pertaining to assets. Manitoba Hydro will supply Kinectrics with available information/data for each of the Asset Categories and any relevant information from subject matter experts for the assessment of data quality and adequacy.

At the completion of this stage, Kinectrics shall provide an interim report to Manitoba Hydro on their assessment of the quantity and quality of the asset data provided by Manitoba Hydro, and on their expected level of confidence in the final results based on their methodologies and the initial availability and quality of the asset data/information. Kinectrics shall also provide a prioritized list of any additional asset information that is required if Manitoba Hydro's data is found to be insufficient.

10.2 Stage 2: Develop & Test Methodologies

Kinectrics shall develop and, using available asset data/information, test methodologies to develop an aging asset management and investment plan for Manitoba Hydro's in-service power transformers, breakers and transmission lines.

Kinectrics shall develop and test customized methodologies to:

i) Assess and rate the condition of each asset on an individual and group basis using available asset information;

ii) Forecast the risk of asset failure for each asset using available asset information based on:
   (1) The probability of failure, as determined by factors such as asset condition, "effective age", performance and expected stresses, and
   (2) The potential quantified consequences of failure including, but not limited to, financial, customer, reliability, environment and safety related impacts;

iii) Estimate the economic end of life for each asset taking into account factors such as the "effective age", risk of asset failure, forecasted operating costs (including maintenance and repair) and anticipated lack of spare parts;

iv) Forecast annual failure rates for asset classes based on the probability of failure and other relevant factors;

v) To prioritize asset investment decisions to maximize overall value to Manitoba Hydro in the event of budget and/or resource constraints;

vi) To optimize investment (replace vs. repair) decisions based on capital cost, forecast maintenance and repair costs, and on the remaining economic life of assets;

vii) To develop 20 year optimized capital and operating expenditure forecasts to sustain Manitoba Hydro's asset base.

Kinectrics shall develop these methodologies based on industry best practices, the available asset data/information, and on input from Manitoba Hydro subject matter experts, and present their proposed methodologies to Manitoba Hydro for review and approval. These methodologies should be consistent with methodologies being employed by other North American and preferably Canadian electric utilities. The methodology described in item vi) shall be an enhancement of Manitoba Hydro's existing Apparatus Maintenance Division Repair/Replace Decision Guide.

Kinectrics shall interview and acquire input from Manitoba Hydro experts on all methodologies to ensure the methodologies reflect Manitoba Hydro's asset data availability, maintenance and operating practices, and knowledge of its assets, as well as Kinectrics's industry experience. This input shall include planned and unplanned asset replacement values and maintenance costs, preference for Risk Assessment approach (e.g. include or not include customer interruption costs, usage of financial risk impacts in prioritization, etc.).

As part of the development and testing of the methodologies, Kinectrics shall:

- Conduct an Asset Condition Assessment (ACA) for transformers, circuit breakers and transmission lines based on the data and information available at Manitoba Hydro and calculate Health Index distributions for all Asset Categories. This will involve using appropriate asset data to produce a quantifiable indicator of asset condition, the Health Index (HI). The HI is based not only on chronological age, but on numerous long term degradation condition parameters that cumulatively lead to the asset's end of life (EOL).
- Perform a risk based assessment which establishes the relationship between the asset's Health Index, the asset's age and the probability of failure, and which quantifies asset risk by using either monetary risk costs or weighted risks to corporate Business Values. The Risk Assessment will determine the optimal time for intervention using the "economic end of life" concept and taking into account risk costs and replacement costs (i.e. determine the optimal time for intervention from an economic perspective by taking into consideration the total life cycle cost of an asset). Kinectrics shall use this optimal replacement time as a basis for a replace vs. refurbish analysis to decide on the most appropriate course of action based on a relationship between replacement and refurbishment costs and effectiveness of refurbishment.
- Evaluate the options available for managing assets (e.g. replace, refurbish, "run to failure", eliminate, modify maintenance practices) and determine the associated financial implications (capital and operating) such as increased maintenance and/or failure rates.

Once Manitoba Hydro has provided its input and feedback on all proposed methodologies, Kinectrics shall apply the methodologies using Manitoba Hydro asset data/information in a spreadsheet format (the Spreadsheet Tool). Kinectrics shall provide an interim report on all the initial results obtained by applying and testing the above methodologies on Manitoba Hydro's asset data. Kinectrics shall also provide the Excel spreadsheet(s) in which the methodologies are implemented to provide the initial results to Manitoba Hydro.

Kinectrics shall use Manitoba Hydro's feedback on these results as input to finalize the methodologies.

10.3 Stage 3: Identify Improvement Opportunities

Kinectrics shall work with Manitoba Hydro subject matter experts to access the applicable current practices, processes and tools and to make recommendations to improve Manitoba Hydro's ability to assess asset conditions, determine the risk of asset failure, estimate the economic end of life, and develop long-term investment plans for power transformers, breakers and transmission lines. As part of this, Kinectrics shall evaluate the need for an asset management software solution. The available options, ranging fron: manual health index evaluations and updates using spreadsheets (as will be applied in this project) to a fully integrated enterprise system that will allow for automatic data consolidation, real-time assessment, monitoring, and trending, shall be explored. Kinectrics shall also identify and evaluate Manitoba Hydro's planned maintenance practices, including preventative maintenance, monitoring and inspections, and make recommendations on improving these practices based on a comparison with industry best practices from other utilities.

10.4 Stage 4: Finalize Methodologies and Submit Final Report

Kinectrics shall use the methodologies developed and tested in Section 10.2 as well as the feedback from Manitoba Hydro experts to finalize the methodologies. Kinectrics shall apply the finalized methodologies to the Spreadsheet Tool and the available asset data, and produce a draft of the Final Report. Manitoba Hydro shall review the draft report and provide feedback to Kinectrics. Kinectrics shall incorporate Manitoba Hydro's recommendations and issue the Final Report along with the finalized Spreadsheet Tool.

The Final Report shall include all the results and findings from the Services. Kinectrics shall provide the report in Microsoft Word format and include the following sections:

1) Executive Summary
2) Project Scope and Objectives
3) Engagement Model
4) Methodologies
5) Expert opinion of Manitoba Hydro Staff
6) Results
7) Conclusions and Recommendations

The Methodologies section shall describe in detail for Manitoba Hydro's transformer, circuit breaker and transmission line assets all the customized methodologies used for each asset category to rate asset condition, to determine forecasts for the risk of failure, failure rates, economic end of life, and capital and operating expenditures, and to optimize investment decisions and prioritize projects based on the above factors. This section shall transfer to Manitoba Hydro sufficient maintenance, failure, follow-up, and end-of-life data are being collected and shall recommend strategies for closing these gaps in a prioritized manner.

- An assessment of whether Manitoba Hydro should implement commercially available asset investment planning and management software tools which could be employed in the future to implement the methodologies and to enhance the long term sustainability of the asset investment planning process. Software tools that can be integrated with existing Manitoba Hydro data systems and provide additional automation and functionality, shall be considered in the assessment.

The Conclusions & Recommendations section of the Final Report shall include the actions required for continuous improvement based on the initial Asset Condition Assessment, such as possibility of using new advanced software solutions, periodic audits, and new technologies.

Along with the Final Report, Kinectrics shall provide to Manitoba Hydro the Microsoft Excel spreadsheet(s) which implement all the finalized methodologies and which was used to produce the asset condition, risk assessment and forecast results provided in the Final Report. The spreadsheet(s) shall include all asset information/data, and all calculated/derived parameters, formulas, logic and statistical analytics used to determine the asset condition ratings, risk assessments and forecasts. The spreadsheet shall be accompanied by a user's manual that describes how the methodologies are implemented in the spreadsheet and how to use the spreadsheet tool.

Kinectrics shall, at the request of Manitoba Hydro, make a presentation on the project to Manitoba Hydro's senior management. The presentation shall include description of methodologies used, results, conclusions and recommendations.

11 PRICING

Summary of Pricing

Stage 1: Preliminary Services and Asset Data Assessment	[redacted]
Stage 2: Develop & Test Methodologies	[redacted]
Stage 3: Identify Improvement Opportunities	[redacted]
Stage 4: Finalize Methodologies and Submit Final Report	[redacted]
Total Price	[redacted]

The GST and PST shall be shown as "extra" on each invoice. All other applicable taxes shall be included.

Kinectrics shall provide a [redacted] discount off the Total Price if all four Stages of the Services are awarded to Kinectrics.

The above prices do not include travel expenses and assume that the required data/information will be provided by Manitoba Hydro to Kinectrics in an electronic format. If Manitoba Hydro decides to use Kinectrics's data experts for extracting condition data from its enterprise systems, Kinectrics shall provide that service at an additional cost. Kinectrics shall provide a separate quote once more is known about where and how Manitoba Hydro's data is stored.

The travel expenses for Kinectrics are estimated to be between $10,000 and $15,000 (Cdn) and will depend on the number of visits by Kinectrics's staff to Manitoba Hydro's facilities. Kinectrics will be reimbursed for its travel expenses by Manitoba Hydro on a cost basis upon submission of receipts.

Kinectrics shall offer an additional [redacted] discount off the Total Price if Manitoba Hydro provides Kinectrics with the permission and support to advertise the leading edge holistic asset management approaches that will be developed under Agreement to other utilities. The advertisement might take the form of a brief article in a trade journal or presentation of the results at a conference with the content subject to Manitoba Hydro approval.

The pricing for each project Stage is on the Firm Price basis and Manitoba Hydro will not be charged more than the amounts shown regardless of the actual costs incurred by Kinectrics. Manitoba Hydro agrees to make the lump sum payment specified above for each stage after the Services for that stage, as defined above in Section 10, have been fully provided by Kinectrics.

all knowledge on the proposed methodologies, including all statistical models, mathematical models, decision logic, and tools utilized in the application and implementation of the methodologies.

The Results section shall, for each Asset Category, include:

- Age distribution
- Health Index distribution
- Data assessment
- Risk assessment/forecast for each asset
- Forecasted Economic End of Life for each asset
- Optimal Asset Investment Plan
- Levelized Asset Investment Plan
- Strategy for prioritized gap closure (i.e. roadmap)

The data assessment portion of the Results section shall summarize for each transformer, circuit breaker and transmission line asset, the values of the asset data/information used in the methodologies proposed by Kinectrics, as well as flags and statistics for missing data. In the report, Kinectrics shall state their level of confidence in the final results based on their methodologies and the availability of the asset data/information, and provide a prioritized list, based on expected costs and benefits, of any additional asset information that is required if Manitoba Hydro's data is found to be insufficient. The portion of the report shall be provided in the form of a written report, or a Microsoft Excel spreadsheet, or a combination of both.

The Asset Investment Plans shall cover a 20-year time period and reflect both capital and maintenance budget requirements for each asset. The Plan shall be based on the Health Index distribution within each asset category, the Risk Assessment for applicable assets, the options selected to manage the assets within each asset category (e.g. replace, refurbish, "run to failure", eliminate, modify maintenance practices) and on non-condition driven investment requirements, such as obsolescence, new generation and load connections, existing load growth, regulatory requirements, municipal work, etc. This Plan shall take into account the number of assets that need to be replaced each year due to the risk of failure and other non-condition related factors (obsolescence, regulatory requirements, system growth, etc.) as well as the number of units that need to be refurbished.

The Results section shall also include the following:

- An assessment of Manitoba Hydro's practices in the areas of maintenance, testing, inspecting, and monitoring of assets, collection of asset information, and the use of technologies to monitor asset condition/health as they pertain to developing long-term asset investment plans for transformer, circuit breaker and transmission line assets. In their analysis, Kinectrics shall consider whether

Manitoba Hydro

Appendix B
Cyber Security

CYBER SECURITY

1 DEFINITIONS

The following words and phrases have the meanings given in the North American Electric Reliability Corporation (NERC) National Reliability Standards: Cyber Assets, Electronic Security Perimeter, Physical Security Perimeter, Bulk Electric System, and Cyber Security Incident.

The following words and phrases have the meanings given:

"Critical Cyber Asset" means a cyber asset that is essential to the reliable operation of the bulk electric system. Examples of potential critical cyber assets include, but are not limited to: protections, controls, station automation systems, distributed control systems, monitoring, and special protection systems.

"Protected Cyber Assets" means Cyber Assets performing access control, monitoring and protection of Critical Cyber Assets; Cyber Assets logically connected to Critical Cyber Assets; or Cyber Assets which could be used to compromise the Critical Cyber Assets.

"Reliability Standards" means the NERC Reliability Standards CIP-002-1 to CIP-009-1 as same is in force and effect from time to time, and any amendments thereto.

"Access Control Systems" (ACS) - The process of granting or denying requests to access physical facilities such as critical hydro buildings control centres or areas such as a critical hydro yards or to logical systems such as computer networks. The systems must be established to track and to detect access to all areas. The system must provide auditing and attendance features. The system must also capable of being remotely administrated in order to control user access. Users of the systems are assigned clearance levels. The systems must comply with the requirements of the NERC Reliability Standards regarding access control

2 GENERAL

The NERC Reliability Standards CIP-002-1 to CIP-009-1 are available for review at the following website: **www.NERC.com.**

The Contractor shall be responsible for obtaining the most current version(s) of the Reliability Standards in force and effect from time to time.

The Purchaser's business activities must be in compliance with the Reliability Standards.

The Contractor acknowledges and understand s the Purchaser's requirem ents and obligations in respect of the Reliability Standards.

The Contractor acknowledges and understand s that the Reliability Standards, and Purchaser implem ented practices and pr ocedures, m ay, fr om tim e to tim e, be revised and placed into force and effect.

The Contractor's obligations under the C ontract the Reliabilit y Standards, apply to:

a) the W ork and the activ ities, busin ess practices, and procedures of the Contractor in respect of, and invo lving, Contractor's perform ance of obligations under the Contract, including performance of the Work; and

b) the Equipment to be, and that are, provided by the Contractor under the Contract.

The Purchaser has the right at any tim e to am end, increase, decrease an d/or add to, any part of these req uirements in cluding any of the Contr actor's obligations, and the Purchaser's rights, hereunder.

The Purchaser's determ ination of the scope, interpretation, m eaning, and application of the Reliability S tandards, any Purchaser p olicies, p ractices and guidelines or any part(s) thereof, sha ll be absolute, final and binding on the Contractor, and shall not be s ubject to any Contractor claim , dispute or arbitration.

If the Contractor ha s any question as to the scop e, interpretation, m eaning, and application of the Reliability S tandards, any Purchaser p olicies, p ractices and guidelines, or any part(s) thereof, th e Contractor shall request, through the Engineer, for the Purchaser's determination on same.

3 SECURITY REQUIREMENTS FOR CONTRACTOR'S ACTIVITIES, PROCESS AND PRACTICES

3.1 Reliability Standards

The Contractor, in perform ing the Work and its obligations under and in respect of the Contract, including, without lim itation, the Contractor 's activities and business practices and procedures, under and in respect of the Contract and with respect to th e W ork, shall enable, an d shall ensure, Purchaser's compliance with the Reliability Standards.

3.2 Purchaser Policies and Guidelines

The Contractor, in perform ing the Work and its obligations under and in respect of the Contract, including, without lim itation, the Contractor 's activities and business practices and procedures, under and in respect of the Contract and with respect to the Work, shall comply with the following Purchaser policies, practices and guidelines (to be provided upon contract award):

a) Manitoba Hydro Information Technology Security Guideline (G71);
b) Manitoba Hydro Information Technology Security Practices;
   i) System & Software Security (P71-1)
   ii) Communication Security (P71-2)
   iii) Data Security (P71-3)
   iv) Physical Security (P71-4)
   v) Change Control (P71-5)
   vi) Security Administration (P71-6); and
c) Manitoba Hydro Personnel Risk Assessment (PRA) (G45D);
d) Manitoba Hydro Security for Facilities and Services (G45)

3.3 Application

Contractor's obligations in respect of potential and actual Cyber Assets, potential and actual Critical Cyber A sset inf ormation, and potenti al and actual Protected Cyber Asset inf ormation applies to such Assets and such inf ornation in the possession and/or control of the Contractor, and that of any Person for whom the Contractor is responsible.

3.4 Inventory

The Contractor shall:

a) create, update, and m aintain a current i nventory of all poten tial and actual Cyber Assets, all poten tial and actu al Critic al Cyber Asset inf ormation, and all potential and actual Protected Cyber Asset inform ation, and regardless whether or not same is, or may be, contained in any Equipment;

b) update such inventory with informa tion received from the Purchaser pursuant to Cyber Assets Section 3.5 Purchaser Verific ation of thi s Appendix; and

c) as and when requested by the Engineer or the P urchaser, but in any event no less than on a quarterly basis co mmencing and continuing from t he Contract Award, review, and deliver to the Purchaser a copy of, such inventory and all updates thereto.

3.5 Purchaser Verification

The Purchaser may, from time to time, provide notice to the Contractor advising whether potential Cyber Assets, potential Critical Cyber Assets, potential Protected Cyber Assets, potential Critical Cyber Asset information and potential Protected Cyber Asset information (identified and delivered by the Contractor in accordance with Cyber Security Section 3.4 Inventory of this Appendix, or any other property or information, are actual Cyber Assets, actual Critical Cyber Assets, actual Protected Cyber Assets, actual Critical Cyber Asset information and actual Protected Cyber Asset information, or of any change in the status of same (including reversal of any previous determination(s)).

3.6 Physical and Electronic Security

In addition to any other requirement(s) in the Contract, including this Appendix, the Contractor shall, performing its obligations under and in respect of the Contract, and in performing the Work, ensure that:

a) the Physical Security Perimeter securing all potential and actual Critical Cyber Asset information and all potential and actual Protected Cyber Asset information, must comprise at least two (2) layers or mechanisms of physical security, with at least one (1) of which must have continuous monitoring and logging functions. A layer or mechanism may be a facility access control such as card access door, room or cabinet lock, security guard and sign-in system, or alarmed intrusion detection system.

b) the Electronic Security Perimeter securing all potential and actual Critical Cyber Asset information and all potential and actual Protected Cyber Asset information, must comprise at least two (2) layers or mechanisms of cyber security, with at least one (1) of which must have continuous monitoring and logging functions. A layer or mechanism may be a firewall, access control such as password protection, strong encryption, access monitoring and logging, or alarmed intrusion detection system.

c) all connections to/from any medium containing potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information, and means for communicating potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information, must be secured by physical and cyber security such as the use of dedicated communications lines, strong encryption, no wireless setups, and remote access management systems.

d) the integrity of potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information must be controlled and managed by edit/print/copy and version control systems satisfactory to the Purchaser.

e) continuous availability of potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information to the Purchaser must be ensured by retention and disposal control, incident response, and off-site backup systems satisfactory to the Purchaser.

The Contractor shall as and when requested by the Engineer or the Purchaser, but in any event no less than on a yearly basis commencing and continuing from the Contract Award, review the capability to safeguard and ensure the confidentiality, integrity and availability to the Purchaser of, Cyber Asset information, and deliver to the Purchaser a copy of documentation and description capable of verifying adequacy of same.

3.7 Confidentiality

3.7.1 The Contractor shall:

(a) keep all potential Critical Cyber Asset information, all actual Critical Cyber Asset information, all potential Protected Cyber Asset information, and all actual Protected Cyber Asset information, confidential and shall not, without the prior written consent of the Purchaser, disclose or otherwise make available any such information to any other Person, except to such directors, officers, and employees of the Contractor who have a need to access any such information to perform their obligations to the Contractor;

(b) cause all applicable Persons to observe the terms of Section 3.7 hereof and shall be responsible for any breach of Section 3.7 hereof by it or any such Person; and

(c) not use any potential Critical Cyber Asset information, any actual Critical Cyber Asset information, any potential Protected Cyber Asset information, or any actual Protected Cyber Asset information, for any purpose other than in connection with the Work, or in any way that may be detrimental to the Purchaser.

3.7.2 The Contractor shall:

(a) secure all potential Critical Cyber Asset information, all actual Critical Cyber Asset information, all potential Protected Cyber Asset information, and all actual Protected Cyber Asset information, (including, without limitation, securing any property used to store, access, or use, any such information) against unauthorized or accidental access, damage, disclosure, or attack; and

(b) provide notice to the Purchaser immediately upon the discovery of any matter described in Section 3.7.2(a) hereof, or of any threat or attempt thereof.

3.7.4 The Contractor acknowledges that any failure to comply with the provisions of Section 3.7 hereof, shall cause irreparable harm to the Purchaser which cannot be adequately compensated for in damages, and accordingly acknowledges that the Purchaser shall be entitled, in addition to any other remedies available to it, interlocutory and permanent injunction relief to restrain any anticipated, present, or continuing breach of Section 3.7.

3.7.5 The Contractor's obligations pursuant to Section 3.7 hereof shall continue without limitation of time.

3.8 Return and Destruction of Information

The Contractor shall:

a) on demand from the Purchaser, deliver potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information to the Purchaser and, within ten (10) days of such demand, certify in writing to the Purchaser that all such information has been delivered.

b) on demand from the Purchaser, erase and destroy potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information and, within ten (10) days of such demand, certify in writing to the Purchaser that all such information has been erased and destroyed.

c) not retain, in any form, format or medium, any potential and actual Critical Cyber Asset information and any potential and actual Protected Cyber Asset information that has been delivered, erased and/or destroyed pursuant to Section 3.7 (a) and (b) above.

4 RISK ASSESSMENT - PERSONS AND CONTRACTOR'S PERSONNEL

4.1 Access

The Contractor shall:

a) ensure all Persons, and all Contractor Personnel, that may and/or will have authorized cyber or authorized unescorted physical access to:
   i) potential and/or actual Cyber Assets
   ii) potential and/or actual Protected Cyber Assets

iii) potential and/or actual Critical Cyber Asset information
iv) potential and/or actual Protected Cyber Asset information,

have been previously cleared by a personnel risk assessment, to the Purchaser's satisfaction, before to being allowed such access.

b) ensure completed forms, included in Schedule A of this Appendix, are submitted,

c) comply with all applicable privacy laws in carrying out its responsibilities under this Appendix,

d) ensure that any change to the criminal background status of any Person or Contractor's Personnel is reported to the Purchaser immediately.

4.2 Documentation

The Contractor shall:

a) create, update, and maintain a current list of all Persons, and all Contractor's Personnel, who have authorized cyber or authorized unescorted physical access to potential and actual Cyber Assets, potential and actual Protected Cyber Assets, potential and actual Critical Cyber Asset information, and potential and actual Protected Cyber Asset Information, including a description of each Contractor's personnel's specific electronic and physical access rights to potential and actual Cyber Assets, potential and actual Protected Cyber Assets, potential and actual Critical Cyber Asset information, and potential and actual Protected Cyber Asset information.

b) update such list within seven (7) days of any change of any Person's or Contractor's Personnel's access rights, including a description of the reason for access change and the date of same.

c) revoke access to such Cyber Assets, Protected Cyber Assets, Critical Cyber Asset information and Protected Cyber Asset information:

i) within 24 hours of termination of a Person or Contractor Personnel for cause;
ii) within seven (7) days for any Person or Contractor Personnel who no longer requires access to such Cyber Assets, Protected Cyber Assets, Critical Cyber Asset information or Protected Cyber Asset information.

d) as and when requested by the Engineer or the Purchaser, but in any event no less than on a quarterly basis commencing and continuing from the

Contract Award, review, and deliver to the Purchaser a copy of, such list and all updates thereto.

The Purchaser may, at any time, require further, or different, personnel risk assessments be conducted in respect of any Person, and a Person's existing clearance may be revoked until such time as a follow-up risk assessment is conducted and satisfactory results have been delivered to the Purchaser.

5 TRAINING

The Contractor shall conduct initial, quarterly, and annual training, for all Persons and all the Contractor's Personnel who may, or will, have authorized cyber access or authorized unescorted physical access to potential and actual Cyber Assets, potential and actual Protected Cyber Assets, and/or potential and actual Critical Cyber Asset information, and/or potential and actual Protected Cyber Asset information.

The form, content, and any other requirements, concerning and for training to be conducted by the Contractor, shall be provided by, and shall be at the direction of, the Purchaser.

The Contractor shall:

a) create, update, and maintain, complete and current records of and concerning all training, including names of attendee's, dates of training, and any other matter directed by the Purchaser.

b) as and when requested by the Engineer or the Purchaser, but in any event no less than on a quarterly basis commencing and continuing from the Contract Award, review and deliver to the Purchaser a copy of such records and all updates thereto.

6 DOCUMENTATION

The Contractor shall:

a) be responsible for the cost of performance of its obligations in respect of Cyber Security Sections 2 GENERAL, 3 SECURITY REQUIREMENTS FOR CONTRACTOR'S ACTIVITIES, PROCESS AND PRACTICES, 4 RISK ASSESSMENT - PERSONS AND CONTRACTOR'S PERSONNEL, 5 TRAINING and 8 DOCUMENTATION of this Appendix.

b) document the Contractor's program for performance of the Contractor's obligations in respect of Sections 2 GENERAL, 3 SECURITY REQUIREMENTS FOR CONTRACTOR'S ACTIVITIES, PROCESS AND PRACTICES, 4 RISK ASSESSMENT - PERSONS AND CONTRACTOR'S PERSONNEL, 5 TRAINING and 8 DOCUMENTATION of this Appendix.

c) provide evidence satisfactory to the Purchaser of performance of any of the Contractor's obligations in respect of Sections 2 GENERAL, 3 SECURITY REQUIREMENTS FOR CONTRACTOR'S ACTIVITIES, PROCESS AND PRACTICES, 4 RISK ASSESSMENT - PERSONS AND CONTRACTOR'S PERSONNEL, 5 TRAINING and 8 DOCUMENTATION of this Appendix.

d) The Purchaser's rights and Contractor's obligations in respect of Sections 2 GENERAL, 3 SECURITY REQUIREMENTS FOR CONTRACTOR'S ACTIVITIES, PROCESS AND PRACTICES, 4 RISK ASSESSMENT - PERSONS AND CONTRACTOR'S PERSONNEL, 5 TRAINING and 8 DOCUMENTATION of this Appendix shall survive the expiry or termination of the Contract, the completion of the Work, and shall continue without limitation of time until:

i) the Contractor, and any Person(s) for whom the Contractor is responsible, no longer has:
1) possession of,
2) control over, and
3) cyber and/or physical access to
potential and actual Cyber Assets, potential and actual Critical Cyber Asset information and potential and actual Protected Cyber Asset information; and

ii) the Purchaser has certified in writing the same.

6.1 Notwithstanding the above, the Contractor's obligations in respect of Section 3.7 Confidentiality,

6.1.1 The Contractor shall:

a) Keep all potential Critical Cyber Asset information, all actual Criter Cyber Asset information, all potential Protected Cyber Asset information, and all actual Protected cyber Asset information, confidential and shall not, without the prior written consent of the Purchaser, disclose or otherwise make available any such information to any other Person, except to such directors, officers, and employees of the Contractor who have a need to access any such information to perform their obligations to the Contractor;

b) cause all applicable Persons to observe the terms of Section 6.1 hereof and shall be responsible for any breach of Section 6.1 hereof by it or any such Person;

c) not use any potential Critical Cyber Asset information, any actual Critical Cyber Asset information, any potential Protected Cyber Asset information, or any actual Protected Cyber Asset information, for any purpose other than in connection with the Work, or in any way that may be detrimental to the Purchaser.

6.1.2 The Contractor shall:

a) secure all potential Critical Cyber Asset information, any actual Critical Cyber Asset information, any potential Protected Cyber Asset information, or any actual Protected Cyber Asset information (including, without limitation, securing any property used to store, access, or use, any such information) against unauthorized or accidental access, damage, disclosre, or attach; and

b) provide notice to the Purchaser immediately upon the discovery of any matter described in 6.1.2 a) hereof, or of any threat or attempt thereof.

6.1.3 The Contractor acknowledges that any failure to comply with the provisions of Section 6.1 hereof, shall cause irreparable harm to the Purchaser which cannot be adequately compensated for in damages, and accordingly acknowledges that the Purchaser shall be entitled, in addition to any other remedies available to it, interlocutory and permanent injunction relief to restrain any anticipated, present, or continuing breach of Section 6.1.

6.1.4 The Contractor's obligations pursuant to Section 6.1 herof shall continue without limitation of time.

Return and Destruction of information in this Appendix shall continue without limitation of time.

7 REQUIREMENTS FOR WORK AND EQUIPMENT

7.1 Reliability Standards

All Work and Equipment, shall be designed, manufactured and supplied such that all of the same enables and ensures compliance with, operation of, application of, and compatibility with, the Reliability Standards and the Purchaser's compliance with the Reliability Standards.

7.2 Purchaser Policies and Guidelines

All Work and Equipment shall be designed, manufactured and supplied such that all of the same enables and ensures compliance with, operation of, application of, and compatibility with, the following Purchaser policies and guidelines , included in Schedule A of this Appendix

a) Manitoba Hydro Information Technology Security Guideline (G71);
b) Manitoba Hydro Information Technology Security Practices;
   i) System & Software Security (P71-1)
   ii) Communication Security (P71-2)
   iii) Data Security (P71-3)
   iv) Physical Security (P71-4)
   v) Change Control (P71-5)
   vi) Security Administration (P71-6); and
c) Manitoba Hydro Personnel Risk Assessment (PRA) (G45D).

7.3 Information Protection

7.3.1 General

All Work and Equipment shall be designed and manufactured so as to be capable to safeguard and ensure the confidentiality, integrity, and availability to Purchaser of, Cyber Asset infor mation. Contra ctor's Docum ents shall include documentation and description capable of verifying adequacy of same.

7.3.2 Access Control

Access to Cyber Asset infor mation that is or m ay be contained in any Work and Equipment shall be capable of m anagement and protection in strict compliance with the requirements herein.

7.3.3 Confidentiality, Integrity and Availability

All Work and Equipment shall be designed, manufactured and supplied such that:

a) the Physica l Security P erimeter sec uring Cyber Asset inf ormation m ust comprise at least two (2) layers or mechanisms of physical security, with at least one (1) of which m ust have continuous m onitoring and logging functions. A layer or m echanism may be a facility access control such as card access door, room or cabinet lock, security guard and sign-in system, or alarmed intrusion detection system.

b) the Electronic Security Perim eter se curing Cyber Asset inf ormation must comprise at least two (2) layers or mechanisms of cyber security, with at least one (1) of whic h m ust have continuous m onitoring and logging functions. A layer or mechanism may be a firewall, access control such as password protection, strong encryp tion, access monitoring and logging, or alarmed intrusion detection system.

c) connections to/from any medium containing Cyber Asset information, and means for comm unicating Cyber Asset information, must be secured by physical and cyber security such as the use dedicate d lines, strong encryption, no wireless setups, and remote access management system.

d) the integrity of Cyber Asset inf ormation must be controlled and m anaged by edit/print/copy and version cont rol system s satisfactory to the Purchaser.

e) continuous availability of Cyber Asset Inform ation to the P urchaser must be ensured by retention and disposal control, incident response, and off-site backup systems satisfactory to the Purchaser.

The Engineer and/or the Purchaser reserv e the right to periodically review the adequacy and application of controls to protect Cyber Asset Information.

7.4 Cyber Asset Requirements

7.4.1 Functionality and Capability

All Work and Equipment shall be designe d, manufactured and supplied such that any Cyber Assets shall:

a) only enab le ports and serv ices required for norm al and em ergency operations. Normal operations include maintenance support.

b) disable other ports and services, incl uding those used for testing purposes, prior to in-service.

c) deny access by default.

d) support the use of anti-virus and malicious software prevention tools.

e) provide m ultiple leve ls of access. Each level shall be p rotected by a password, at a minimum.

f) provide historical audit tr ail logs of individual us er account activity for a minimum of 90 days. The Purchaser sh all be able to cha nge th is time period as may be required from time-to-time.

g) provide an audit trail of administrator, shared, default and generic account activity for a m inimum of 90 days. The Purchaser shall be a ble to change this time period as may be required from time-to-time.

h) have passwords with a minim um of s even characters. Each password shall consist of a com bination of alpha, nu meric and "special" ch aracters. The passwords shall be changed by the Purchaser as may be required from time-to-time.

i) issue alerts for any attempted or actual unauthorized or accidental access, damage, disclosure, attack, and any and all cyber security event(s) including, without limitation, password changes, administrator level access changes, security log changes. The set of triggers and the contents of the notifications should be fully configurable.

j) log all security events related to cyber security for a minimum of 90 days.

k) support the implementation of cyber security patches and security upgrades. Security patches and security upgrades may be to hardware, software, or firmware.

l) provide for and include current and ongoing Contractor and third-party support for security patches and security upgrades.

7.4.2 Documentation

The Contractor shall:

a) provide a list of all required ports (physical and logical), internet protocol port traffic, configuration of ports and services, and expected protocols for all Cyber Assets and associated networks.

b) provide documentation on recommended test procedures to ensure that significant changes do not adversely impact cyber security controls. Significant changes include at a minimum, but are not limited to: implementation of security patches, cumulative service packs, vendor releases, and upgrades of operating systems, applications, database platforms, software or firmware, including those provided by third-party vendors. Test procedures shall minimize adverse affects on the production system and its operation.

c) document complete details regarding device and system cyber security.

d) document all cyber security testing and implementation, which includes, but is not limited to: ports and services, significant changes, security patches, anti-virus and malware prevention tools.

e) list supported anti-virus and malware prevention tools.

f) document the process for the update of the anti-virus and malware prevention tools, including testing and installation.

g) identify and document all administrators, shared, and other generic account privileges, including factory default accounts.

h) provide a list of all individuals with access to individual, administrator, shared or generic accounts prior to in-service operation.

i) provide a documented vulnerability assessment and recommended process.

7.4.3 Pre-Operational Service Requirements

The Contractor shall:

a) include testing to ensure that only ports and services required for normal operation are enabled. All other ports and services shall be disabled.

b) provide security patches that shall:
   i) include testing of all current and applicable security patches, including vendor and third-party security patches.
   ii) conduct security testing in a manner that reflects the production environment.
   iii) remove, or disable administrator, shared, default and generic accounts not required for normal and emergency operations. Remaining account passwords shall be changed prior to in-service operation.

7.4.4 Operational Service Requirements

The Contractor shall ensure that security patches shall:

a) include testing of all current and applicable security patches, including vendor and third-party security patches.

b) provide a recommendation whether or not to apply the patch to the Purchaser within fourteen (14) days of the patch release.

c) conduct security testing in a manner that reflects the production environment.

7.5 Electronic Access Control and Monitoring

All Work and Equipment shall be designed, manufactured and supplied such that:

a) Critical Cyber Assets shall reside in an Electronic Security Perimeter.

b) Cyber Assets logically connected to Critical Cyber Assets shall reside in an Electronic Security Perimeter.

c) Electronic Security Perimeters should be defined to reduce or remove non-critical Cyber Assets logically connected to Critical Cyber Assets.

d) All electronic access points to the Electronic Security Perimeter shall be controlled. Electronic access points include any externally connected communication end point terminating at any device within the Electronic Security Perimeter.

e) All Cyber Assets performing access control, monitoring and protection of Critical Cyber Assets shall meet all the requirements identified in Section 7.4 Cyber Asset Requirements of the SECURITY Section of the Technical Requirements and the additional requirements identified in this Section.

All Work and Equipment shall be designed, manufactured and supplied such that the electronic access control and monitoring shall:

i) Provide two or more distinct security measures to protect the Electronic Security Perimeter.

ii) Authenticate all electronic access through the electronic access points with strong controls. Examples include, but are not limited to, two-factor authentication and digital certificates.

iii) Electronically separate Critical Cyber Assets and Protected Cyber Assets from the Purchaser's business data network by a firewall or firewalls. The Purchaser reserves the option to provide these firewalls, and will configure these firewalls.

iv) Support an appropriate use sign-on banner configurable by the Purchaser.

v) Monitor and log all access to electronic access points 24 hours a day, 7 days a week.

vi) Retain electronic access logs for a minimum of 90 days.

vii) Prevent non-administrators from gaining undue privileges.

7.6 Electronic Access Logging System

All Work and Equipment shall be designed, manufactured and supplied such that the electronic access logging system shall:

a) Log the following information for all access attempts: account name, date and time (session start and end), station name, system identifier, Electronic Security Perimeter, and electronic access point.

b) Generate a separate log entry for each electronic access point.

c) Log and flag failed access attem pts (account nam e, date and tim e, access point).

d) Log the actions of the administrators.

e) Save the logs into a database. The database should be replicated.

f) Protect the database containing the log files from unauthorized modification or deletion.

g) Have a central repo rting facility to generate rep orts fr om the logs. The Contractor shall includ e a sam ple of log reports that co uld be used to satisfy the requirements of the Reliability Standards.

h) Allow for report templates to be created and saved.

i) Provide a search engine to query across multiple logs.

j) Allow the administrator to schedule reports to be run at defined intervals.

k) Generate logs to create a historical audit trai l of account activity for a minimum of 90 days. L ogs shall co ntain: account nam e, access date an d time (entry and exit), station nam e, sy stem identifier, Elec tronic Security Perimeter, and electron ic acces s po int. The Pu rchaser shall be ab le to change this time period as may be required from time-to-time.

7.7 Documentation

The Contractor shall deliver documentation to:

a) Identify and document each Electronic Security Perimeter. Documentation shall in clude all in terconnected Cyber Assets and all electron ic acces s points. This shall inclu de electroni c access points on network devices including, but not limited to, hubs, routers and switches.

b) Document the authentication methods.

c) Identify and docum ent the discovery process of all acc ess points to the Electronic Security Perimeter.

d) Identify and docum ent all adm inistrators, shared, network m anagement community strings, and other generic account privileges, including factory default accounts.

e) Document all configurations and processes of the production system when placed in o peration. All subsequ ent chang es shall be docum ented an d approved prior to application to the production system.

7.8 Physical Security for Cyber Assets

7.8.1 Physical Security Perimeter

All Work and Equipment shall be designed, manufactured and supplied such that:

a) all Critical Cyber Assets and Cyber A ssets logically conne cted to Critic al Cyber Asse ts sha ll b e loca ted in a Physical Security P erimeter. T he Physical Se curity Perim eter shall be a six -walled, com pletely enclos ed border.

b) All physical access points through the Physical Security Perimeter shall be controlled and managed.

c) All physical access to Cyber Assets perform ing access electronic an d physical control, monitoring and protec tion of Critical Cyb er Assets, shall be controlled and managed.

d) Physical Security Perim eters shall be defined to reduce or rem ove non-critical Cyber Assets within the secured perimeter.

e) Physical access to cabling which electrically connects Cyber Assets within the Electronic Security Perimeter shall be controlled and managed.

f) Cabling which extends th e E lectronic Secu rity Perim eter outsid e of a Physical Security Perim eter shall be physically enclosed and protected. Examples of physical cable protec tion include, but are not lim ited to, conduit and cable armour.

g) all network cabling within the E lectronic Security Perim eter shall be terminated within a Ph ysical Secur ity Perimeter. This inc ludes, but is n ot limited to, termination cubicles, wiring closets and patch panels.

7.8.2 Access Controls

All Work and Equipm ent shall be designe d, manufactured and supplied such that physical access controls shall:

a) Be provided for all Critical Cyber Assets and all Protected Cyber Assets.

b) Authenticate all physical access.

c) Be provided 24 hours a day, 7 days a week.

d) Provide two different and complementary methods of physical access controls:
   i) card key
   ii) special locks
   iii) security personnel who may reside on-site or at a monitoring station
   iv) other equivalent authentication devices, which may include, but are not limited to: biometrics, keypads or tokens.

7.8.3 Monitoring

All Work and Equipment shall be designed, manufactured and supplied such that physical access monitoring shall:

a) be provided at all physical access points for Critical Cyber Assets and Protected Cyber Assets.

b) be provided 24 hours a day, 7 days a week.

c) occur in real time for immediate response.

d) immediately alarm all unauthorized access and unauthorized access attempts. Methods include, but are not limited to:
   i) alarm systems: indicate that a door, window, gate or other access has been opened without authorization; and provide real-time alarming and notification to response personnel.
   ii) Human observation by authorized security personnel.

7.8.4 Logging Physical Access

All Work and Equipment shall be designed, manufactured and supplied such that physical access logging shall:

a) Be provided at all physical access points for all Critical Cyber Assets and all Protected Cyber Assets.

b) Log all physical access 24 hours a day, 7 days a week.

c) Uniquely identify individuals.

d) Record time and date of access.

7.8.5 Access Log Retention

All Work and Equipment shall be designed, manufactured and supplied such that all physical access logs shall be retained for a minimum of 90 days. The Purchaser shall be able to change this time period as may be required from time-to-time.

7.8.6 Physical Access Logging System Requirements

All Work and Equipment shall be designed, manufactured and supplied such that the physical access logging system shall:

a) Log the following information for all access attempts: individual's name, date and time (entry and exit), station name, building identifier, physical security perimeter, and physical access point.

b) Generate a separate log entry for each physical access point.

c) Log and flag failed access attempts (who, when and which access point).

d) Log the actions of the administrators.

e) Save the logs into a database. The database should be replicated.

f) Protect the database containing the log files from unauthorized modification or deletion.

g) Have a central reporting facility to generate reports from the logs. The Contractor shall include a sample of log reports that could be used to satisfy the requirements of the Reliability Standards.

h) Allow for report templates to be created and saved.

i) Provide a search engine to query across multiple logs.

j) Allow the administrator to schedule reports to be run at defined intervals.

k) Generate logs to create a historical audit trail of individual access activity for a minimum of 90 days. Logs shall contain: individual's name, access date and time (entry and exit), station name, building identifier, Physical Security Perimeter, and physical access point. The Purchaser shall be able to change this time period as may be required from time-to-time.

7.8.7 Documentation Requirements

The Contractor shall deliver documentation that identifies:

a) All Physical Security Perimeters

b) All Critical Cyber Assets and Cyber A ssets logically connected to Critical Cyber Assets within each Physical Security Perimeter.

c) All access points through the Physical Security Perimeter.

d) Access controls to manage access for each physical access point.

e) Monitoring methods for each physical access point.

f) Logging methods for each physical access point.

g) Recommended physical security maintenance and testing procedures.

7.9 Recovery

7.9.1 Backup and Restore

The Contractor shall docum ent the pro cesses and procedures required to backup and restore Critical Cyber Assets and Protected Cyber Assets.

7.10 Change Control and Maintenance

In respect of the W ork and Equipment including, without lim itation performance of the Work and the Contractor's obligations under and in respect of the Contract, including, without lim itation, the Contracto r's activities, business practices and procedures, under and in respect of the Contract and with respect to the Work, the Contractor shall im plement a pro cess of change control and configuration management.

The process shall include, at a m inimum, processes for adding, modifying, replacing, or removing Critical Cyber A sset and Protected Cyber Asset hardware, software, configurations and settings , and identifying, controlling, and documenting all changes, including third-party vendor related changes.

The Contractor shall docum ent its proce ss of change control and configuration management. The process shall include, at a m inimum, processes for adding, modifying, replacing, or rem oving Critic al C yber Asset and Protected Cyber Asset hardware, software, configura tions and settings , and identifying, controlling, and docum enting all ch anges, inc luding th ird-party vendor related changes.

SCHEDULE A

BackCheck™

Manitoba Hydro

Contractor Service Order Form – Contractor Company Verification

Know Who You're Hiring
www.backcheck.ca

1. Client Contact Information: CORPORATE SECURITY USE ONLY	
Company: ▾ Manitoba Hydro	Date: (yyyy/mm/dd) ▾ / /
Faxed By: ▾	Phone Number: ▾
Email Results to: ▾ @hydro.mb.ca (Corporate Security)	# of Pages: ▾

2. Service Menu – please ☒ services requested

☒ Name Based CDN Criminal Record Verification with Identity Cross-Check

3. Contractor Company representative please complete the following:

MH Project Manager: ▾

ID Check is MANDATORY for a Name Based Criminal Record Check

Two (2) pieces of legible identification are required:

1. The first of which must be government-issued and include the applicant's name, date of birth, signature and photo (e.g. *Driver's License, Passport, Citizenship Card, Permanent Resident Card, Certificate of Indian Status*).
2. The second should be government-issued, however at minimum it must include the full name of the candidate.

~ Please send legible copies of the identification to BackCheck along with this cover and consent form. ~

Contracting Company: ▾	Contractor Name: ▾	Position Applied For: ▾

ID Verification One (1):	Type: ▾	Identification Number: ▾
ID Verification Two (2):	Type: ▾	Identification Number: ▾

I ______________________ have examined the identification of ______________________
Print Name of Representative | Print Name of Contractor
and I am satisfied that the candidate and person depicted in the photo identification are one and the same.

Signature of Contractor Company Rep.
Confirming ID Check:
X

4. Contractor Contact Information: **(Note: If applicant does not have a personal address, they must list an email address where identity check can be sent to)**

Primary Phone Number: ▾	Secondary Phone Number: ▾	E-mail Address (REQUIRED): ▾

Please E-mail or Fax the corresponding BackCheck consent forms along with supporting documents:
- ☐ **Copy of Candidate's ID**

Please ensure printing is 100% legible

E-mail: orders@backcheck.ca
Toll Free Fax: 1-866-323-3097
Fax: 604-323-3097

BackCheck™

Consent Form A

Consent for Disclosure of Personal Information

Name Based Canadian Criminal Record Verification with Identity Cross-Check

To ensure accuracy, you must PRINT in clear CAPITAL letters and complete this form in its entirety.

PLEASE NOTE: The following information and photocopies of identification are for identification purposes only, allowing BackCheck to accurately proceed with the assembly of a name based criminal record verification for employment purposes. BackCheck will hold all personal information confidential.

Given Name(s):▼	Middle Name(s):▼	Gender:▼ *Check One* ☒ ☐ Male ☐ Female
Surname:▼	Maiden name, aliases, nicknames and any other names:▼	
Place of Birth:▼ (City / Province / Country)		Date of Birth:▼ / / (yyyy mm dd)
Current Address:▼ (Unit Number / Street Number / Street Name / Postal Code)		
Current Address Continued:▼ (City / Province / Country)	From:▼ / / (yyyy mm dd)	To:▼ / / (yyyy mm dd)
Previous Address – If less than 5 years ago:▼ (Unit Number / Street Number / Street Name / Postal Code)		
Previous Address Continued:▼ (City / Province / Country)	From:▼ / / (yyyy mm dd)	To:▼ / / (yyyy mm dd)
Telephone Number:▼	Alternative Telephone Number:▼	Position Applied For:▼

I certify that the information in this Disclosure for Personal Information is true and correct to the best of my ability.

Declaration of Offences

Have you been convicted of a criminal offence for which a pardon has not been granted? ☐ Yes ☐ No

Have you been granted a conditional discharge within the past three (3) years? ☐ Yes ☐ No

Have you been granted an absolute discharge within the past year? ☐ Yes ☐ No

If you have answered Yes to any of the above questions, please provide details on ALL convictions (attach additional pages if required):

Offence	Date (yyyy/mm/dd)	Location	Penalty
	/ /		
	/ /		

Disclaimer: The existence of a conviction will not preclude you from consideration for employment or a contract position with Manitoba Hydro. Details of the offence are requested to enable Manitoba Hydro to determine whether the offence is related to your employment or intended employment.

Statement of Understanding and Consent

I have applied to Manitoba Hydro for employment or a contract position. Part of the screening process includes a search of the National Criminal Records repository, known as the Canadian Police Information Centre (CPIC) database, maintained by the RCMP using the name(s) and date of birth provided above. BackCheck conducts these investigations on behalf of Manitoba Hydro.

I hereby consent and authorize a Canadian Police Department to search for and disclose on my behalf to BackCheck who is requesting a name based Canadian criminal record verification on behalf of Manitoba Hydro the fact that records may exist on me and are registered on the CPIC database. I acknowledge that such records may include information relating to criminal convictions under the *Criminal Code* (Canada) for which a pardon has not been granted and conditional and absolute discharges which have not been removed from the CPIC database in accordance with the *Criminal Records Act*.

I authorize BackCheck to release all information obtained to Manitoba Hydro and hold harmless BackCheck upon the release of this information or its findings to Manitoba Hydro. I understand that failing to provide accurate information or omission of facts herein may disqualify me from consideration for employment or a contract position with Manitoba Hydro.

Furthermore, if there is a discrepancy with the information provided by myself on this form and that disclosed by a Canadian Police Department during this investigation of my criminal records history, I understand that I have the option to provide my fingerprints to resolve any discrepancy or dispute.

This request is made in compliance with any applicable provincial or municipal public sector privacy legislation which allows a public body or municipality to disclose my personal information to me or my agent upon my request, and in particular in accordance with the Nova Scotia *Municipal Government Act* and the Ontario *Municipal Freedom of Information and Protection of Privacy Act.*

Contractor Signature: *Authorizing Name Based Criminal Record Verification* X	Date: (yyyy/mm/dd)▼ / /
Contractor Company – Hiring Manager: *Witnessing the candidate's signature* X	Date: (yyyy/mm/dd)▼ / /

Identity Cross-Check

In connection with my application for employment or a contract position with Manitoba Hydro I understand that the background check process includes an identity cross-check based on retrieval of information from a major Canadian credit bureau.

I consent to identification verification based on information retrieved from a major Canadian credit bureau. I consent to the release of identity cross-check components of the consumer credit bureau report by BackCheck to Manitoba Hydro.

Contractor Signature: *Authorizing Identity Cross-Check* X	Date: (yyyy/mm/dd)▼ / /

THIS AGREEMENT effective as at the **September 20, 2012.**

BETWEEN:

MANITOBA HYDRO,
(hereinafter called "Hydro"),

OF THE FIRST PART,

- and -

KINECTRICS INC.
(hereinafter called the "Consultant"),

OF THE SECOND PART.

WHEREAS the parties entered into an agreement dated the **16 of JANUARY, 2012** (hereinafter referred to as the "Consulting Agreement");

NOW THEREFORE the parties agree as follows:

1. **THAT** Kinectrics will supply the LineVue equipment and required technical support to provide one week (5 days) of transmission line condition testing services. Kinectrics will deliver a report on the condition of the core of each transmission line section tested.

   Kinectrics will provide these services, which have an estimated value of [redacted] to Manitoba Hydro at no additional cost in exchange for Manitoba Hydro forgoing the following payment discounts identified in Section 11 of Terms of Reference:
   a) Kinectrics shall provide a [redacted] discount off the Total Price if all four Stages of the Services are awarded to Kinectrics.
   b) Kinectrics shall offer an additional [redacted] discount off the Total Price if Manitoba Hydro provides Kinectrics with the permission and support to advertise the leading edge holistic asset management approaches that will be developed under Agreement to other utilities.

2. **THAT** all provisions of the Consulting Agreement shall be deemed to be incorporated herein except where they are inconsistent or incompatible with this Agreement.

3. **THAT** this Agreement shall extend to, be binding upon and ensure to the benefit of the parties hereto, their successors and assigns.

IN WITNESS WHEREOF the parties have caused this Agreement to be executed on the day and year first above written.

Signed in the presence of:

WITNESS

MANITOBA HYDRO

Authorized Signing Officer

Signed in the presence of:

WITNESS

KINECTRICS INC.

Authorized Signing Officer

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

Appendix C refers to a third part consultant which worked with various Manitoba Hydro departments in developing asset condition assessment methodologies and statistical failure models for transmission elements.

QUESTION:

Identify the exact name of the model or models used to generate the condition assessment methodologies and statistical failures.

RATIONALE FOR QUESTION:

Asset condition assessment methodology review and analysis is a central element in testing reasonableness of expenditure.

RESPONSE:

Kinectrics Inc. has developed its own proprietary condition assessment methodology framework for transformers, breakers and transmission line wood pole structures, which is their intellectual property. Kinectrics Inc. worked with Manitoba Hydro to customize its methodology and to develop spreadsheet based tools to incorporate Manitoba Hydro transmission asset information and data sources (e.g. maintenance management system and laboratory information management system) into Kinectrics condition assessment framework.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

Appendix C refers to a third part consultant which worked with various Manitoba Hydro departments in developing asset condition assessment methodologies and statistical failure models for transmission elements.

QUESTION:

Please identify other utilities that used similar models.

RATIONALE FOR QUESTION:

Asset condition assessment methodology review and analysis is a central element in testing reasonableness of expenditure.

RESPONSE:

Kinectrics Inc. has worked with numerous utilities on condition assessment related projects, including Exelon, Toronto Hydro, Hydro One, Brampton Hydro One and Powerstream.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

Appendix C refers to a third part consultant which worked with various Manitoba Hydro departments in developing asset condition assessment methodologies and statistical failure models for transmission elements.

QUESTION:

Is the model or models discussed in the appendix C a risk model or an asset management model?

RATIONALE FOR QUESTION:

Asset condition assessment methodology review and analysis is a central element in testing reasonableness of expenditure.

RESPONSE:

Neither. The model provides a condition parameters score that locates the asset on a statistical failure curve, determining an asset health index score to classify an asset's condition.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide all the statistical failure models produced by the third party consultant in electronic format with all formulae intact.

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

The requested models are proprietary in nature and are the intellectual property of the third party consultant and therefore cannot be provided.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the statistical failure models for:

i. Breakers
ii. Transformers
iii. Transmission line wood poles

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-100a.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

For the statistical failure models mentioned on part (b) please identify the following:

i. The part based on consultants industry failure curves
ii. The part based on subject matter expert input
iii. The part based on Manitoba Hydro input

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-100a.

Section:	Tab 4 Appendix 4.2, Appendix C	Page No.:	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the industry failure curves used. When were they developed and when will they be updated in the future?

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-100a.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please identify how the statistical models produced by the third party consultant progress through time and how they treat potential replacements

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-100a. The model does not assess potential replacements over time.

Section:	Tab 4 Appendix 4.2, Appendix C	**Page No.:**	p. 89
Topic:	Capital Expenditure Forecast		
Subtopic:	Statistical failure models		
Issue:	Review and assess the validity of the statistical failure models		

PREAMBLE TO IR (IF ANY):

QUESTION:

Did the classification of the asset condition include any risk analysis related to the impact of the loss of the asset? If yes, please provide evidence in the condition parameter calculation or statistical failure model.

RATIONALE FOR QUESTION:

Validate statistical failure models.

RESPONSE:

Please see Manitoba Hydro's response to COALITION/MH-I-100a.

Section:	Tab 4 Appendix 4.2, Appendix D	**Page No.:**	p. 106
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please define risk and valuation as it used in the asset condition assessment methodology for distribution assets.

RATIONALE FOR QUESTION:

Test reasonableness of asset prioritization.

RESPONSE:

The reference to risk and valuation found on page 106 was included in error, as those factors are not taken into consideration in distribution asset condition assessment.

Section:	Tab 4 Appendix 4.2, Appendix D	Page No.:	p. 106
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please identify how risk is incorporated into the asset condition assessment.

RATIONALE FOR QUESTION:

Test reasonableness of asset prioritization.

RESPONSE:

As noted in the response to COALITION/MH-I-101a, risk is not incorporated into distribution asset condition assessment. Asset condition is only one component within the risk management and investment prioritization process.

Section:	Tab 4 Appendix 4.2, Appendix D	**Page No.:**	p. 106
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide documentation that denote how the following are incorporated in the asset condition methodology assessment. Does Manitoba Hydro use a weighted scoring approach or the below are equally weighted:

i. Asset Age
ii. Asset Type
iii. Inspection Programs
iv. Maintenance Programs
v. Historical Data

RATIONALE FOR QUESTION:

Test reasonableness of asset prioritization.

RESPONSE:

The asset condition methodology employed by Manitoba Hydro is reflective of the nature of its distribution system, as distribution plant is typically comprised of large numbers of discrete, geographically dispersed assets.

For example, Manitoba Hydro has over one million distribution poles in service throughout the province, and the sources of information used in assessing pole condition may be different from that used to assess the condition of other asset categories. Pole condition may be more efficiently gauged by sampling pole groups and statistically analyzing the results.

Therefore, while all five sources of information noted above and in the report at page 106 were considered in the determination of the condition of each asset type, some sources of information provided better insight into the state of a particular asset's condition, and therefore were relied upon for the analysis of distribution asset groups.

Section:	Tab 4 Appendix 4.2, Appendix D	**Page No.:**	p. 106
Topic:	Capital Expenditure Forecast		
Subtopic:	Asset condition Assessment methodology		
Issue:	Asset condition assessment methodology assessment		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please identify how the statistical models progress through time and how they treat potential replacements

RATIONALE FOR QUESTION:

Test reasonableness of asset prioritization.

RESPONSE:

Manitoba Hydro does not use a statistical model for the evaluation of the condition of distribution assets.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm that since the overnight rate has been 1.0%, the three month Treasury Bill yield has also been about or 1.0%.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

The 3 month Treasury Bill yield has been slightly above or below 1.0% since September 8, 2010 when the overnight interest rate was last increased to 1.0%. The highest 3 month Treasury Bill yield (Bank of Canada V-series V39065, daily series) between September 2010 and December 2014 was 1.06% on April 24-27, 2012 and the lowest was 0.77% on January 9, 2012.

Section:	3.2	**Page No.:**	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm that both RBC and the National Bank forecast that the T Bill yield would increase by 0.25% in 2015 Q2 with further increases in 2015Q3 and 2015Q4 and that every forecaster predicted that the T. Bill yield would increase by 2015Q4

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Table 1 on page 2 of Appendix 3.2 provides the forecasted rates of Canadian 3 month T-Bill rates from each of the sources, expressed on an average period basis, used to develop the consensus forecast assumed in the 2015 IFF. The forecasts from all of the sources were completed prior to the Bank of Canada's 0.25% reduction to the target overnight rate on January 21, 2015.

With reference to page 2 of Appendix 3.2, as at September 1, 2014, the RBC forecast of the 3 month T-Bill rate was 1.23% for 2015 Q2. At October 1, 2014, the National Bank forecast of the 3 month T-Bill rate was 1.25% for 2015 Q2. It is also noted that at September 19, 2014 BMO forecasted the 3 month T-Bill rate to be 0.93% for 2015 Q2 while the remaining sources forecasted the 3 month T-Bill rate to be at or slightly above 1.0% by 2015 Q2.

With the exception of BMO and Laurentian, the forecasts of all of the sources used for IFF14 show interest rates above 1.0% for the Canadian 3 month T-Bill rate by 2015 Q3 with further growth in 2015 Q4 by all sources.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm that the Bank of Canada cut the overnight rate on January 21, 2015, which was not predicted by any forecaster, and the T Bill yield has subsequently dropped to 0.88% (13/2/2015).

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

It is confirmed that the Bank of Canada cut the overnight rate from 1.0% to 0.75% on January 21, 2015, which was not predicted by any of the forecasters used by Manitoba Hydro in preparing the fall 2014 update.

It is not confirmed that the 3 month T-Bill yield dropped to 0.88% on 13/2/2015. According to the Bank of Canada (V-series V39065, daily series), the 3 month T-Bill yield dropped to 0.51% on February 13, 2015.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm the following extracts from RBC (financial markets monthly with their interest rate forecasts) for February 4, 2015.

	Actuals				Forecast							
	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4
Canada												
Overnight	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	0.75	1.00	1.50	2.00
Three-month	0.90	0.94	0.92	0.91	0.50	0.50	0.65	0.85	1.15	1.40	1.65	2.15
Two-year	1.07	1.10	1.13	1.01	0.55	0.70	0.85	1.05	1.50	1.75	2.00	2.30
Five-year	1.71	1.53	1.63	1.34	1.00	1.35	1.60	1.80	2.15	2.35	2.60	2.80
10-year	2.46	2.24	2.15	1.79	1.65	2.10	2.35	2.55	2.90	3.10	3.30	3.45
30-year	2.96	2.78	2.67	2.34	2.25	2.65	2.90	3.05	3.30	3.45	3.60	3.75

RATIONALE FOR QUESTION:

Manitoba Hydro’s IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Confirmed.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm that RBC's forecast T. Bill yield has dropped by 1.0% as of 2015Q4.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Confirmed.

Section:	3.2	**Page No.:**	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please provide copies of all recent interest rate forecasts consistent with those provided in Appendix 3.2

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Please see the response to PUB/MH-I-75c.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please update the MH short term rate on page 3 for the new forecast interest rates.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH-I-75c for an updated forecast of Manitoba Hydro's Canadian short-term interest rate forecast.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please provide the understanding from Manitoba Hydro in terms of why the guarantee fee is 1% regardless of term. Is it MH's judgment that credit spreads are the same on three month versus thirty year debt issues?

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

The Provincial Guarantee Fee (PGF) is a flat fee assessed on all applicable debt regardless of varying terms to maturity or credit spreads. Manitoba Hydro is a Crown Corporation and is subject to the PGF. The fee is set by the Province of Manitoba, and Manitoba Hydro is unable to comment on the Province's rationale as to why the PGF is 1% regardless of term.

It is Manitoba Hydro's judgment that credit spreads in the financial markets typically vary between three month versus thirty year debt issues.

Section:	3.2	**Page No.:**	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please confirm that RBC's forecast ten year bond yield for 2015Q4 has dropped from 3.85% to 3.05% or 0.80%.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Not confirmed.

RBC's end-of-period forecast of the 30 year bond rate and not the 10 year bond rate for 15Q4 was 3.85% in their September 2014 outlook and 3.05% in their February 4, 2015 forecast.

Since RBC's September 2014 outlook, their end-of-period forecast of the 10 year bond rate for 15Q4 has decreased from 3.55% to 2.55% in their February 4, 2015 forecast.

Please note that Manitoba Hydro uses the average of the forecasted Canadian 10 year and 30 year bond rates to determine a benchmark Canadian 10 year+ rate.

Section:	3.2	**Page No.:**	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please provide MH long term interest rate forecast (page 4) for 2015 and 2016 using the interest rates collected in answer to (f) above.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH-I-75c for an updated forecast of Manitoba Hydro's Canadian long-term interest rate forecast.

Section:	3.2	Page No.:	3
Topic:	Interest Rate Forecast		
Subtopic:	Revenue Requirement		
Issue:	Forecast interest Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro forecasts its short term borrowing cost based on an average of Canadian forecasts around September 2014.

QUESTION:

Please update the data in Appendix 11.12 for the updated interest rate forecast.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. The credibility of its forecasts is at issue.

RESPONSE:

Please see the following table for the updated interest rate scenario found in Attachment A and the updated interest rates and net extraprovincial revenue scenario found in Attachment B of the response to PUB/MH-I-10b.

Attachment A – Updated Interest Rates

Fiscal Year Ended	Debt/ Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt*	Retained Earnings
2015	78:22	0.98	1.16	16,993	102	11,854	2,717
2016	82:18	1.03	1.19	18,860	128	14,034	2,791
2017	83:17	0.98	1.11	21,779	89	16,769	2,880
2018	84:16	1.15	1.10	24,922	95	19,649	2,974
2019	85:15	0.95	0.95	26,515	(50)	21,210	2,925
2020	86:14	0.92	0.94	27,583	(65)	22,311	2,860
2021	87:13	0.94	0.91	28,205	(106)	22,879	2,754
2022	88:12	1.12	0.91	27,637	(106)	22,716	2,648
2023	88:12	1.27	0.93	27,685	(84)	22,858	2,564
2024	88:12	1.41	0.99	27,902	(14)	23,083	2,549
2025	88:12	1.44	1.05	27,819	60	22,927	2,609
2026	87:13	1.50	1.08	27,996	95	23,008	2,703
2027	86:14	1.67	1.17	28,407	208	23,201	2,911
2028	85:15	1.78	1.23	28,693	284	23,193	3,195
2029	83:17	1.89	1.33	29,035	400	23,126	3,594
2030	81:19	2.15	1.46	29,481	540	23,029	4,134
2031	78:22	2.24	1.59	29,462	678	22,302	4,811
2032	75:25	2.40	1.74	30,254	794	22,283	5,604
2033	71:29	2.49	1.84	31,099	877	22,247	6,480
2034	67:33	2.61	1.97	32,069	973	22,241	7,453

* Long term plus short term debt

Attachment B – Updated Interest Rates and Net Extraprovincial Revenues

Fiscal Year Ended	Debt/ Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt*	Retained Earnings
2015	78:22	0.98	1.16	16,993	102	11,854	2,717
2016	82:18	0.98	1.14	18,860	101	14,061	2,763
2017	84:16	0.94	1.08	21,779	67	16,820	2,830
2018	85:15	1.11	1.08	24,922	74	19,717	2,904
2019	86:14	0.91	0.93	26,515	(73)	21,304	2,831
2020	87:13	0.86	0.92	27,584	(92)	22,433	2,739
2021	87:13	0.87	0.88	28,205	(153)	23,040	2,586
2022	89:11	1.03	0.87	27,637	(156)	22,927	2,430
2023	89:11	1.18	0.89	27,687	(137)	23,124	2,292
2024	89:11	1.31	0.94	27,864	(73)	23,367	2,220
2025	89:11	1.35	1.00	27,823	(0)	23,313	2,219
2026	89:11	1.37	1.01	27,961	14	23,437	2,233
2027	88:12	1.54	1.10	28,258	122	23,601	2,355
2028	88:12	1.64	1.15	28,654	190	23,793	2,545
2029	86:14	1.74	1.24	28,897	302	23,726	2,846
2030	84:16	1.99	1.36	29,242	439	23,629	3,284
2031	82:18	2.09	1.48	29,120	575	22,902	3,858
2032	79:21	2.26	1.62	29,808	690	22,883	4,547
2033	76:24	2.35	1.71	30,547	771	22,847	5,318
2034	72:28	2.47	1.82	31,409	866	22,841	6,183

* Long term plus short term debt

Section:	5	**Page No.:**	24
Topic:	Exchange Rate hedging Policy		
Subtopic:	Revenue Requirement		
Issue:	Forecast Exchange rate forecasts and impact		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims it mitigates the impact of foreign exchange rate volatility by maintaining a natural hedge with US dollar interest expense.

QUESTION:

Please indicate whether MH's hedging policy removes all FX impact on its cash flows or its cash flows and balance sheet. Please support your conclusion.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. This goes to the credibility of its forecasts.

RESPONSE:

Manitoba Hydro operates in a complex economic environment that simultaneously affects many parts of its operations. Manitoba Hydro's exposures to foreign currency rate fluctuations on United States dollar (USD) revenues are managed with the combination of natural and accounting hedges. For example, to the extent that the underlying USD inflows and outflows are in balance, while a strengthening US dollar will increase the translation of US export revenues into Canadian dollars (CAD), this change will be offset by increases in the translation of US dollar expenses (such as US dollar interest expense) into CAD.

Manitoba Hydro has provided sensitivity analysis in Appendix 3.6 with respect to +/- $0.10 change in the USD/CAD exchange rate. For example, as shown in Figure 3.6.1, as the incremental increase or decrease in retained earnings to 2020/21 is only +/- $3 million, the Corporation's net exposure to USD/CAD currency fluctuations is almost entirely eliminated.

Section:	5	**Page No.:**	24
Topic:	Exchange Rate hedging Policy		
Subtopic:	Revenue Requirement		
Issue:	Forecast Exchange rate forecasts and impact		

PREAMBLE TO IR (IF ANY):

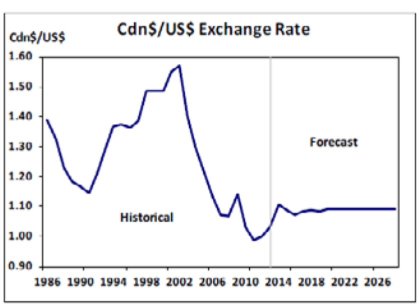
Manitoba Hydro claims it mitigates the impact of foreign exchange rate volatility by maintaining a natural hedge with US dollar interest expense.

QUESTION:

In its original filing MH used the following FX rate forecasts, essentially keeping the C$ rate constant at about 1.09 US. At the time of its interest rate update (September 2014) RBC used the FX rate forecast that follows the MH graphic and for convenience RBC's current forecast (February 4, 2015 follows its October 8, 2014 forecast. Please confirm this data

OUTLOOK:

Economic Outlook 2014 forecasts that the Canadian dollar is expected to remain low for the rest of the year and into the near term with a slight appreciation of a few cents. As the Bank of Canada will likely increase interest rates in 2015 this will pressure the Canadian dollar to increase, however, this change won't be very significant as the survey suggests the Federal Reserve to also move rates at similar times. Accordingly, narrowing Canada/U.S. interest rates will keep the dollar low and well below parity.



Year	US$/ Cdn.$	Cdn.$/ US$
1970	0.96	1.04
1975	0.98	1.02
1980	0.86	1.17
1985	0.73	1.37
1990	0.86	1.17
1995	0.73	1.37
1996	0.73	1.36
1997	0.72	1.38
1998	0.67	1.48
1999	0.67	1.49
2000	0.65	1.49
2001	0.64	1.55
2002	0.71	1.57
2003	0.77	1.40
2004	0.83	1.30
2005	0.88	1.21
2006	0.93	1.13
2007	0.94	1.07
2008	0.94	1.07
2009	0.88	1.14
2010	0.97	1.03
2011	1.01	0.99
2012	1.00	1.00
2013	0.97	1.03
2025	0.92	1.09
2035	0.92	1.09

RBC September 2014 FX rate Forecast

	Actuals							Forecast				
	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4
Canadian dollar	1.02	1.05	1.03	1.06	1.11	1.07	1.12	1.15	1.16	1.17	1.17	1.18
Euro	1.28	1.30	1.35	1.38	1.38	1.37	1.26	1.23	1.20	1.18	1.17	1.17
U.K. pound sterling	1.52	1.52	1.62	1.66	1.67	1.71	1.62	1.60	1.56	1.49	1.44	1.43
New Zealand dollar	0.84	0.77	0.83	0.82	0.87	0.88	0.78	0.79	0.77	0.76	0.75	0.75
Japanese yen	94.2	99.1	98.3	105.3	103.2	101.3	109.7	111.0	113.0	115.0	118.0	120.0
Australian dollar	1.04	0.91	0.93	0.89	0.93	0.94	0.87	0.88	0.87	0.86	0.85	0.85

RBC February 4, 2015 forecast

	Actuals				Forecast							
	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4
Canadian dollar	1.28	1.33	1.12	1.16	1.28	1.33	1.34	1.33	1.32	1.31	1.30	1.29
Euro	1.07	1.05	1.26	1.21	1.07	1.05	1.07	1.11	1.15	1.16	1.16	1.17
U.K. pound sterling	1.47	1.40	1.62	1.56	1.47	1.40	1.41	1.44	1.47	1.49	1.49	1.50
New Zealand dollar	0.87	0.88	0.78	0.78	0.69	0.67	0.65	0.64	0.63	0.63	0.62	0.62
Japanese yen	103.2	101.3	109.7	119.7	120.0	124.0	128.0	132.0	129.0	126.0	123.0	120.0
Australian dollar	0.93	0.94	0.87	0.82	0.75	0.74	0.73	0.72	0.71	0.71	0.70	0.70

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. This goes to the credibility of its forecasts.

RESPONSE:

At the time of producing Manitoba Hydro's spring Economic Outlook in April 2014, the forecast of CAD/USD exchange rate from 2020/21 and on was 1.09 (refer to "Appendix A" of Manitoba Hydro's Spring 2014 Economic Outlook which is filed as part of Appendix 3.1 of Manitoba Hydro's GRA).

An update to the forecast of CAD/USD exchange rate was prepared for use in IFF14 based upon the consensus of source forecasts as of September 2014. The CAD/USD exchange rate forecast used in IFF14 reflects a consensus rate of 1.10 from 2019/20 and on (refer to "Appendix A-Fall 2014 Update" which is filed as the last page of Appendix 3.1 of Manitoba Hydro's GRA).

The table below was extracted from RBC's September 2014 Economic and Financial Market Outlook report and reflects the values used in Manitoba Hydro's September 2014 consensus forecast and IFF14. Manitoba Hydro can confirm the RBC September 2014 data points for

USD/CAD as included in the table provided in the question, with the exception of the 14Q3 value as this value was still a forecast (1.10) at the time Manitoba Hydro obtained RBC's forecast in September 2014, as noted in the table below.

	Actual						Forecast						Actual		Forecast	
	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	2012	2013	2014	2015
AUD/USD	1.04	0.91	0.93	0.89	0.93	0.94	0.94	0.95	0.93	0.92	0.91	0.90	1.04	0.89	0.95	0.90
USD/CAD	1.02	1.05	1.03	1.06	1.11	1.07	1.10	1.15	1.16	1.17	1.17	1.18	0.99	1.06	1.15	1.18
EUR/USD	1.28	1.30	1.35	1.38	1.38	1.37	1.30	1.30	1.28	1.27	1.26	1.25	1.32	1.38	1.30	1.25
USD/JPY	94.2	99.1	98.3	105.3	103.2	101.3	104.0	103.0	103.0	105.0	107.0	110.0	86.8	105.3	103.0	110.0
NZD/USD	0.84	0.77	0.83	0.82	0.87	0.88	0.85	0.86	0.86	0.85	0.84	0.82	0.83	0.82	0.86	0.82
USD/CHF	0.95	0.95	0.90	0.89	0.89	0.89	0.93	0.94	0.96	0.97	0.98	0.99	0.92	0.89	0.94	0.99
GBP/USD	1.52	1.52	1.62	1.66	1.67	1.71	1.65	1.69	1.71	1.65	1.59	1.56	1.62	1.66	1.69	1.56

The table below was extracted from RBC's February 4, 2015 Financial Markets Monthly report and shows the "Canadian dollar" exchange rate at that time expressed as CAD/USD. Manitoba Hydro can confirm the RBC February 4, 2015 data points for USD/CAD as included in the table provided in the question, with the exception of the 14Q1 and 14Q2 actual values. The actual values are 1.11 and 1.07, respectively, as shown in the table below.

	Actuals				Forecast							
	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4
Canadian dollar	1.11	1.07	1.12	1.16	1.28	1.33	1.34	1.33	1.32	1.31	1.30	1.29
Euro	1.38	1.37	1.26	1.21	1.07	1.05	1.07	1.11	1.15	1.16	1.16	1.17
U.K. pound sterling	1.67	1.71	1.62	1.56	1.47	1.40	1.41	1.44	1.47	1.49	1.49	1.50
New Zealand dollar	0.87	0.88	0.78	0.78	0.69	0.67	0.65	0.64	0.63	0.63	0.62	0.62
Japanese yen	103.2	101.3	109.7	119.7	120.0	124.0	128.0	132.0	129.0	126.0	123.0	120.0
Australian dollar	0.93	0.94	0.87	0.82	0.75	0.74	0.73	0.72	0.71	0.71	0.70	0.70

Section:	5	**Page No.:**	24
Topic:	Exchange Rate hedging Policy		
Subtopic:	Revenue Requirement		
Issue:	Forecast Exchange rate forecasts and impact		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims it mitigates the impact of foreign exchange rate volatility by maintaining a natural hedge with US dollar interest expense.

QUESTION:

Please provide an updated foreign exchange rate forecast consistent with current market conditions.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. This goes to the credibility of its forecasts.

RESPONSE:

Table 1 below presents the forecast of CAD/USD exchange rate for the period 2014/15 – 2033/34 based on an update of end of January 2015 source forecasts. For copies of the source forecasts please refer to Manitoba Hydro's response to PUB/MH I-75c.

Table 1: CAD/USD Exchange Rate ($) – January 2015 Update

2014/15	1.13
2015/16	1.29
2016/17	1.25
2017/18	1.13
2018/19	1.11
2019/20	1.10
2020/21	1.09
2021/22	1.09
2022/23	1.09
2023/24	1.10
2024/25	1.10
2025/26	1.10
2026/27	1.10
2027/28	1.10
2028/29	1.10
2029/30	1.10
2030/31	1.10
2031/32	1.10
2032/33	1.10
2033/34	1.10

Section:	5	Page No.:	24
Topic:	Exchange Rate hedging Policy		
Subtopic:	Revenue Requirement		
Issue:	Forecast Exchange rate forecasts and impact		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims it mitigates the impact of foreign exchange rate volatility by maintaining a natural hedge with US dollar interest expense.

QUESTION:

Please update the extra-provincial revenue forecast for current foreign exchange market conditions and discuss whether or not its natural hedge policy represents a perfect hedge.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. This goes to the credibility of its forecasts.

RESPONSE:

Please see the response to COALITION/MH-I-103a, which demonstrates that the Corporation's net exposure to USD/CAD currency fluctuations is almost entirely eliminated through to 2020/21.

Section:	5	Page No.:	24
Topic:	Exchange Rate hedging Policy		
Subtopic:	Revenue Requirement		
Issue:	Forecast Exchange rate forecasts and impact		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro claims it mitigates the impact of foreign exchange rate volatility by maintaining a natural hedge with US dollar interest expense.

QUESTION:

Please update the financial forecast in Appendix 11.8-11.14 under two scenarios: First, MH is allowed a 3.95% per year rate increase each year with both the updated interest rate and foreign exchange rate forecast; second MH is allowed an inflationary 2% a year increase with the new interest rate and foreign exchange rate forecasts

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. This goes to the credibility of its forecasts.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

It is Manitoba Hydro's understanding that the Coalition has withdrawn this Information Request.

Section:	4	Page No.:	20
Topic:	Depreciation Rate		
Subtopic:	Revenue Requirement		
Issue:	Asset Life Expectancy		

PREAMBLE TO IR (IF ANY):

In Figure 4.18 Manitoba Hydro claims that the turnover of its assets at current replacement rates generally exceeds their life expectancy. For example generators have a 60 year life, but given their rate of replacement it will take 117 years to replace them.

QUESTION:

Please confirm that the statement (line 5, page 16) that a 'majority of MH's equipment remains in service well beyond industry expectations without causing significant impact on reliability' could be interpreted as indicating that depreciation rates are too aggressive and that life expectancy is actually significantly longer than MH assumes.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. While most depreciation questions are left to the PUB and MIPUG, this goes to issues of intergenerational equity.

RESPONSE:

As per line 5, page 20 of Tab 4, Manitoba Hydro can find examples in the majority of its asset types where equipment is lasting longer than originally expected, but this is <u>not</u> to say that the majority of Manitoba Hydro's overall equipment is lasting longer than industry expectations.

To the benefit of ratepayers, Manitoba Hydro's maintenance, spares and contingency programs have been effective at deferring the need for capital replacements by extracting the maximum service life from its assets. Reductions in depreciation rates in the 2010 and 2014 depreciation studies reflect the effectiveness of these programs in extending asset service lives and as such Manitoba Hydro does not agree that its depreciation rates are too aggressive. The reductions have resulted in annual decreases in depreciation expense for the fiscal periods 2014/15 through to 2016/17 as follows:

(in millions of dollars)

	2014/15	**2015/16**	**2016/17**
2010 Depreciation Study service life impacts	46	49	51
2014 Depreciation Study service life impacts	25	29	30
Total Decrease in Depreciation Expense	$71	$78	$81

Manitoba Hydro recognizes that many of its infrastructure assets were installed around the same time periods (i.e. prior to 1960, with a second mass installation occurring in the period 1960-1990) such that a majority of its assets are reaching or exceeding maximum age at approximately the same time. Current turnover rates are not representative of expected asset service lives as much of Manitoba Hydro's original asset infrastructure is still in-service and has yet to be replaced. As replacement of aged infrastructure is made, turnover rates should align more with expected service lives.

The effectiveness of the maintenance programs and the overall reliability of the system is at risk as more assets age beyond their expected service lives. This concern is documented on lines 4 and 5 of page 19 and lines 1 and 2 of page 20 of Tab 4 as follows, *"Manitoba Hydro can effectively manage its assets through the use of maintenance, spares and contingency strategies when the majority of assets in a particular asset class are in fair to very good condition. However, as larger percentages of these assets fall into the poor and very poor categories, system failures regretfully will occur more frequently."* To mitigate the impacts on system reliability it is essential that investments in asset renewal be undertaken.

Section:	4	**Page No.:**	20
Topic:	Depreciation Rate		
Subtopic:	Revenue Requirement		
Issue:	Asset Life Expectancy		

PREAMBLE TO IR (IF ANY):

In Figure 4.18 Manitoba Hydro claims that the turnover of its assets at current replacement rates generally exceeds their life expectancy. For example generators have a 60 year life, but given their rate of replacement it will take 117 years to replace them.

QUESTION:

For each asset type in Figure 4.18 provide a table with the current net book value of the asset along with a weighted average composite average life expectancy of the rate base along with the associated average depreciation rate.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. While most depreciation questions are left to the PUB and MIPUG, this goes to issues of intergenerational equity.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	4	Page No.:	20
Topic:	Depreciation Rate		
Subtopic:	Revenue Requirement		
Issue:	Asset Life Expectancy		

PREAMBLE TO IR (IF ANY):

In Figure 4.18 Manitoba Hydro claims that the turnover of its assets at current replacement rates generally exceeds their life expectancy. For example generators have a 60 year life, but given their rate of replacement it will take 117 years to replace them.

QUESTION:

Assuming that the turnover data in Figure 4.18 represents the true life expectancy for MH's rate base, calculate the average "true" life expectancy and associated composite depreciation rate.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. While most depreciation questions are left to the PUB and MIPUG, this goes to issues of intergenerational equity.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	4	**Page No.:**	20
Topic:	Depreciation Rate		
Subtopic:	Revenue Requirement		
Issue:	Asset Life Expectancy		

PREAMBLE TO IR (IF ANY):

In Figure 4.18 Manitoba Hydro claims that the turnover of its assets at current replacement rates generally exceeds their life expectancy. For example generators have a 60 year life, but given their rate of replacement it will take 117 years to replace them.

QUESTION:

Please provide the forecast data in Appendix 11.8-11.14 using this new depreciation rate, reflecting MH's actual replacement rates.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. While most depreciation questions are left to the PUB and MIPUG, this goes to issues of intergenerational equity.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	4	**Page No.:**	20
Topic:	Depreciation Rate		
Subtopic:	Revenue Requirement		
Issue:	Asset Life Expectancy		

PREAMBLE TO IR (IF ANY):

In Figure 4.18 Manitoba Hydro claims that the turnover of its assets at current replacement rates generally exceeds their life expectancy. For example generators have a 60 year life, but given their rate of replacement it will take 117 years to replace them.

QUESTION:

Please update the financial forecast in Appendix 11.8-11.14 under two scenarios: First, MH is allowed a 3.95% per year rate increase each year with both the updated interest rate and foreign exchange rate forecasts along with this « new » depreciation rate; second MH is allowed an inflationary 2% a year increase with the new interest rate and foreign exchange rate forecasts and assumed depreciation rates.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro. While most depreciation questions are left to the PUB and MIPUG, this goes to issues of intergenerational equity.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Tab 3 Appendix 3.4 Appendix 3.5 Appendix 3.6 Appendix 3.8	Page No.:	Page 20, line 32 & continuing to page 21 Page 1 & 2 of 6 Attachment a, b, c and d Page 11 of 40
Topic:	Financing expense		
Subtopic:	Probability of a cut in one or more bond ratings and a change in market appetite for or spreads of Manitoba Bonds leading to an identifiable increase borrowing costs		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ...".

Consumers' Coalition notes that Manitoba Hydro comments on Moody's "negative" trend on page 20 of Tab 3, and on page 21, that "It is important that ... weakened financial ratios ... do not negatively impact the credit rating."

Consumers' Coalition observes that the Morrison Park Advisors ("MPA") report filed in the NFAT proceeding, comments on certain aspects of rating agencies actions and market behaviours.

Consumers' Coalition also notes that Appendix 3.8 does not contain the S&P rating reports. The Consumers' Coalition observes that the S&P web site offers a "Supplementary Analysis: Province of Manitoba, dated 10-Dec--2014", which document provides, "In our opinion, a sharp deterioration in the province's after-capital results leading to a sustained increase in tax-supported debt beyond 180% of consolidated operating revenues, or a significant decline in cash and investment holdings could result in a negative outlook revision or downgrade." This document also indicates a "Tax-supported debt" level for 2013 of approximately 152.6, declining to 151.2 for 2016.

Consumers' Coalition wishes to understand the degree or strength of linkage between bond ratings and the actual rates and spreads which debt instruments trade in the market.

QUESTION:

a) Is it the credit rating that is important or the price at which debt is obtained in the financial markets?

b) Does Manitoba Hydro accept the proposition advanced by MPA at page 69 of 94 that "Projecting forward ten, ... years to a possible financial distress episode at Manitoba Hydro on the basis of current estimates is a tenuous exercise at best, both because of the time involved, and because of the vagaries of the credit rating world" and if not, why not.

c) Is it Manitoba Hydro's position that as rating agencies classify borrowers into various rating classes, that the rating level is indicative or determinative of the spread that the market applies to the borrowers bonds?

d) Does Manitoba Hydro accept the proposition advanced by MPA at page 71 of 94 that "the pattern of the credit spread between Manitoba bonds and Government of Canada bonds does not correspond to the rating agency views", and if not please explain why not, and provide the correct proposition to link ratings and market credit spreads?

e) As MPA notes at page 70 of 94 that "In the past twenty years, Moody's has upgraded Manitoba's credit rating three times", Consumers' Coalition wishes to understand if Manitoba can identify if within a week of any of those upgrades, whether the indicated market rate of 10 year Manitoba bonds changed by a such a degree so as to create a direct line to the rating event and the change in market rates?

f) Does Manitoba Hydro accept the proposition advanced by MPA at page 71 of 94 that "both Moody's and DBRS increased Manitoba's credit rating in 2003, after the spread had already declined, with no apparent further affect once their new positions were announced", and if not please explain why not, and provide the market yields and spreads to support the alternative proposition?

g) As MPA notes at page 70 of 94 that "DBRS rates Manitoba equal to Quebec, but less than Ontario, while Standard and Poors rates Manitoba one notch above Ontario and two notches above Quebec", and Manitoba Hydro presents similar information in Figure 3.9 in Tab 3, Consumers' Coalition wishes to understand if Manitoba Hydro can demonstrate through market yield and spread data related to 10 year obligations of Manitoba, Ontario, Ontario Hydro, Quebec and Quebec Hydro, whether the opinion of DBRS, Moody's or S&P appears to be best reflected in the yields of 10 year debt instruments?

h) As MPA notes at page 70 of 94 that "DBRS rates Manitoba equal to Quebec, but less than Ontario, while Standard and Poors rates Manitoba one notch above Ontario and two notches above Quebec", and Manitoba Hydro presents similar information in Figure 3.9 in Tab 3, Consumers' Coalition wishes to understand if Manitoba Hydro can demonstrate through market yield and spread data related to 20 year obligations of Manitoba, Ontario, Ontario Hydro, Quebec and Quebec Hydro, whether the opinion of DBRS, Moody's or S&P appears to be best reflected in the yields of 20 year debt instruments?

i) As MPA notes at page 70 of 94 that "DBRS rates Manitoba equal to Quebec, but less than Ontario, while Standard and Poors rates Manitoba one notch above Ontario and two notches above Quebec", and Manitoba Hydro presents similar information in Figure 3.9 in Tab 3, Consumers' Coalition wishes to understand if Manitoba Hydro can demonstrate through market yield and spread data related to 10 year obligations of Manitoba, Ontario, Ontario Hydro, Quebec and Quebec Hydro, the value of a "notch" reduction in rating reflected in the 10 year debt instruments?

j) As MPA notes at page 70 of 94 that "DBRS rates Manitoba equal to Quebec, but less than Ontario, while Standard and Poors rates Manitoba one notch above Ontario and two notches above Quebec", and Manitoba Hydro presents similar information in Figure 3.9 in Tab 3, Consumers' Coalition wishes to understand if Manitoba Hydro can demonstrate through market yield and spread data related to 20 year obligations of Manitoba, Ontario, Ontario Hydro, Quebec and Quebec Hydro, the value of a "notch" reduction in rating reflected in 20 year debt instruments?

k) In light of the 180% threshold indicated "Supplementary Analysis: Province of Manitoba, Publication date 10-Dec-2014", and the current and forecast levels of approximately 150% please comment on timing of and likelihood of a "downgrade" in respect of the base case and each of the sensitivities found in Attachments A, B, C, and D of Appendix 3.5 and the -1% interest rate scenario found at page 11 of 40 in Appendix 3.6.

l) Consumers' Coalition wishes to understand the precise meaning of the term "self-supporting" as that term is used through-out the application.

  i. Over what period of time, perhaps a quarter, a year, 3 years, 5 or more years is the status of "self-supporting" determined or established?

  ii. Was Manitoba Hydro's debt "self-supporting" during fiscal 2004, a year of a $436 million loss, and if not, why?

iii. Was Manitoba Hydro's debt "self-supporting" during the fiscal 2003 through 2005 period, a period with a net loss of approximately $229 million, and if not, why?

iv. Is the concept of "self-supporting" based on financing expenses and net income, or interest costs ignoring any capitalization of interest on funds borrowed for major new generation, transmission or head office costs and net income, or some other measures?

RATIONALE FOR QUESTION:

Goes to reliability of IFF and implications for access to affordable credit. Seeks different insight than MMF/Hydro 1-2 or PUB questions.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Appendix 3.1 Appendix 3.2 Appendix 3.7	**Page No.:**	Page A-1 and Fall Update Page 4 of 4 Charts 2 & 3
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ..."

Consumers' Coalition observes in Appendix 3.2, page 4 of 4, that 10 Year + spreads are provided for only 3 fiscal years, 2014/15, 2015/16 and 2016/17, not the 20 years of the forecast nor even the "first 10 years of the financial forecast".

Consumers' Coalition observes in Appendix 3.7, Manitoba Hydro provides chart 2, indicating 10 Year + rates ranging from approximately 4% to approximately 4.5% during the 2005 through 2008 periods and in chart 3, 10 Year + spreads for the same period ranging from approximately 35 basis points to approximately 55 basis points.

Consumers' Coalition observes in Appendix 3.1, that 10 Year + rates between 4% and 4.5% appear in fiscal years 2016/17, 2017/18 and 2018//19 on page A-1, and in the Fall update page, for years 2017/18 to and including 2034/35.

QUESTION:

a) Please confirm that the interest rates in this application are based upon the values in Fall update page, or specify which rates and years vary from those based on the Fall update values?

b) Please provide the forecast 10 Year + spreads for each year to and including 2034/35.

c) Please provide a table with the data used to develop the line in Chart 2 of Appendix 3.7, averaged on a quarterly basis, for the quarters in 2005 through 2008 portion of the period covered in the Chart.

d) Please provide a table with the data used to develop the line in Chart 3 of Appendix 3.7, averaged on a quarterly basis, for the quarters in 2005 through 2008 portion of the period covered in the Chart.

e) If the spreads in this application, provided in part (b) above, for the periods during which the interest rates forecast pages A-1 and the Fall update are between 4% and 4.5%, are not within the approximate range of 35 basis points to 55 basis points, please provide the rationale for the variance, and provide details of a period in the market which is reflective of similar interest rates and higher spreads used in the financial forecast.

f) As the base rates forecast on Fall update page are constant at 4.45% commencing in 2019-20, would it not be reasonable or logically consistent to forecast low credit spreads which are generally lower than those that have been seen in periods of market turbulence?

RATIONALE FOR QUESTION:

Goes to credibility of Hydro forecasts which are relevant to rates.

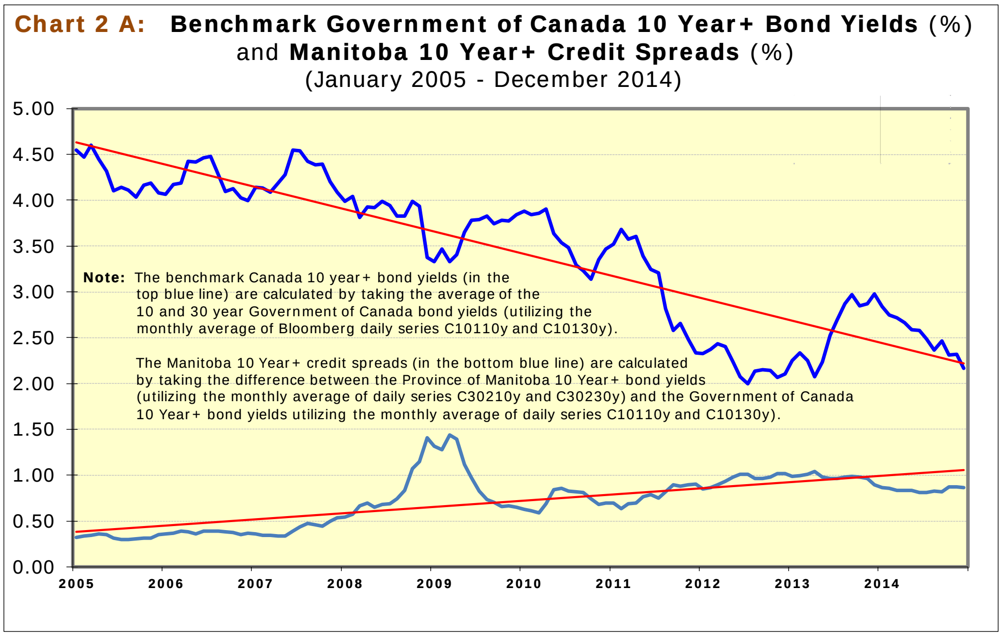
RESPONSE:

<u>The following answer is the response to COALITION/MH I-106a-f</u>:

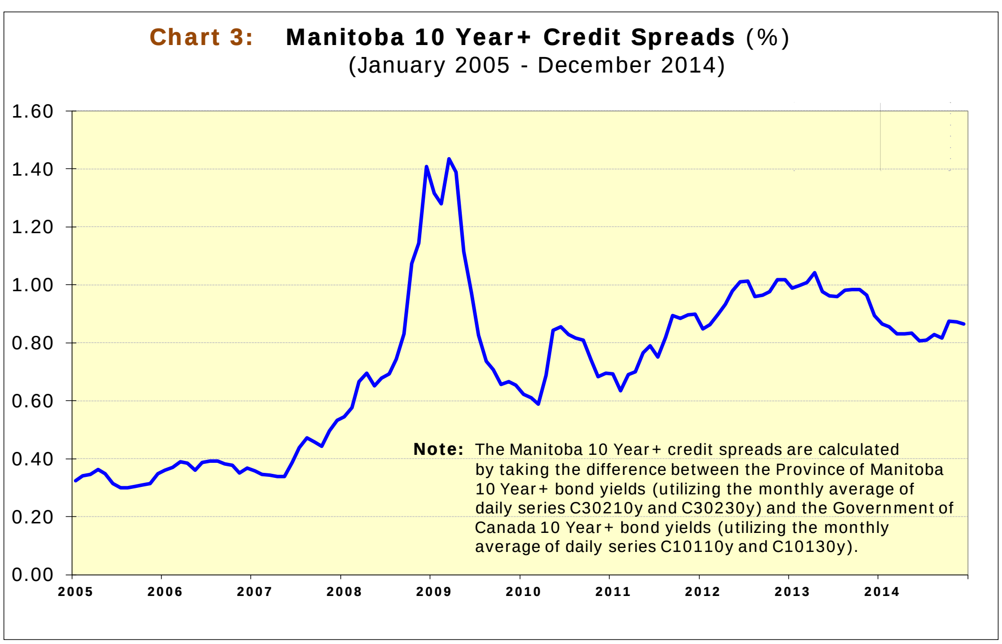
The forecasted interest rates in this Application are based upon the values in the Fall update to the Economic Outlook. The forecasted 10 Year+ credit spreads within the Application are as outlined in response to PUB/MH I–75c. The data points for the two Debt Management Strategy charts cited in this information request used the monthly average of daily data (see the data points in Attachment 1 to this information request).

When the information from the two charts are plotted on the same chart, along with a red trendline for each data series, an inverse, partially counterbalancing relationship is observed between benchmark Canada 10 Year+ bond yields and Manitoba 10 Year+ credit spreads (see the following chart).

The trendlines over the period from January 1, 2005 to December 31, 2014 would generally suggest that should benchmark Canada bond yields decline, there may be a partially offsetting increase in Manitoba credit spreads. Conversely, should benchmark Canada bond yields begin to rise, there may be a partially offsetting decrease in Manitoba credit spreads.



However, a closer examination of the provincial credit spreads in the original Chart 3 (with the vertical axis ranging to 1.60%) show a flat period from 2005 – 2008 (and within a narrow range) prior to the market disruption of the financial crisis, after which the credit spreads from 2010 to 2014 have been at elevated levels (and with a broader range).



A primary driver of the ongoing elevated provincial credit spreads since the financial crisis has been the growth in governmental debt levels. In 2007, the total Canadian federal and provincial government debt issuance was just over $100 billion; however, by 2009 this issuance more than doubled to $215 billion. Post-financial crisis, Canadian dollar government debt issuance has remained at the elevated levels of approximately $200 billion per year.

It is anticipated that the market forces that have led to the high levels of government debt issuance and provincial credit spreads over the last few years will continue through the test years and into the near future.

Relying exclusively upon staledated information from the 2005 – 2008 timeframe (or earlier), and simply adding a 35 to 55 basis points credit spread to forecasted benchmark Canada rates, would not be a justifiable basis for a reasonable forecast of Manitoba Hydro's 10 Year+ long term interest rate.

Manitoba Hydro considers current market conditions and also incorporates 10 years of historical data in its determination of the forecasted Manitoba 10 Year+ credit spread. Moving forward, Manitoba Hydro will continue to monitor the financial markets, including Manitoba's credit spreads, on an ongoing basis.

Attachment 1 - Appendix 3.7 Debt Management Strategy Data for Charts 2 and 3

The monthly averages for the period January 2005 to December 2014 are as follows:

Note that the MB 10 Year+ Rate in this table excludes transaction costs of ~ 6 basis points.

Year	Month	GoC Yield 10 Year+ (Chart 2)	MB Spread 10 Year+ (Chart 3)	MB 10 Year+ Rate	MB Spread/ GoC Rate (10 Year+)
2005	J	4.55	0.32	4.87	7.1 %
	F	4.47	0.34	4.81	7.6 %
	M	4.60	0.34	4.94	7.5 %
	A	4.45	0.36	4.81	8.2 %
	M	4.32	0.35	4.66	8.1 %
	J	4.10	0.31	4.41	7.7 %
	J	4.14	0.30	4.44	7.3 %
	A	4.11	0.30	4.41	7.3 %
	S	4.03	0.31	4.34	7.6 %
	O	4.17	0.31	4.48	7.4 %
	N	4.18	0.32	4.50	7.5 %
	D	4.08	0.35	4.43	8.5 %
2006	J	4.07	0.36	4.43	8.8 %
	F	4.17	0.37	4.54	8.9 %
	M	4.19	0.39	4.58	9.3 %
	A	4.43	0.38	4.81	8.7 %
	M	4.42	0.36	4.78	8.1 %
	J	4.47	0.39	4.85	8.7 %
	J	4.48	0.39	4.87	8.7 %
	A	4.28	0.39	4.67	9.2 %
	S	4.10	0.38	4.48	9.3 %
	O	4.13	0.38	4.50	9.1 %
	N	4.03	0.35	4.38	8.7 %
	D	4.00	0.37	4.36	9.2 %
2007	J	4.14	0.36	4.50	8.6 %
	F	4.14	0.35	4.48	8.4 %
	M	4.09	0.34	4.43	8.4 %
	A	4.19	0.34	4.53	8.1 %
	M	4.28	0.34	4.62	7.9 %
	J	4.55	0.39	4.93	8.5 %
	J	4.54	0.44	4.97	9.7 %
	A	4.42	0.47	4.89	10.7 %
	S	4.38	0.46	4.84	10.4 %
	O	4.39	0.44	4.83	10.1 %
	N	4.20	0.50	4.70	11.8 %
	D	4.09	0.53	4.62	13.0 %
2008	J	3.99	0.54	4.53	13.6 %
	F	4.04	0.58	4.62	14.3 %
	M	3.81	0.66	4.47	17.5 %
	A	3.93	0.69	4.62	17.7 %
	M	3.92	0.65	4.57	16.6 %
	J	3.99	0.68	4.66	17.0 %
	J	3.94	0.69	4.64	17.5 %
	A	3.83	0.74	4.57	19.4 %
	S	3.83	0.83	4.66	21.7 %
	O	3.99	1.07	5.06	26.9 %
	N	3.94	1.14	5.08	29.1 %
	D	3.38	1.41	4.79	41.7 %
2009	J	3.33	1.31	4.65	39.5 %
	F	3.47	1.28	4.75	36.9 %
	M	3.33	1.44	4.77	43.1 %
	A	3.41	1.39	4.80	40.8 %
	M	3.65	1.11	4.77	30.5 %
	J	3.78	0.97	4.75	25.7 %
	J	3.79	0.83	4.62	21.8 %
	A	3.82	0.74	4.56	19.2 %
	S	3.75	0.71	4.45	18.9 %
	O	3.78	0.66	4.44	17.4 %
	N	3.77	0.67	4.44	17.6 %
	D	3.84	0.65	4.49	17.0 %

Year	Month	GoC Yield 10 Year+ (Chart 2)	MB Spread 10 Year+ (Chart 3)	MB 10 Year+ Rate	MB Spread/ GoC Rate (10 Year+)
2010	J	3.88	0.62	4.50	16.1 %
	F	3.84	0.61	4.45	15.9 %
	M	3.85	0.59	4.44	15.3 %
	A	3.90	0.69	4.59	17.6 %
	M	3.64	0.84	4.48	23.2 %
	J	3.54	0.86	4.39	24.2 %
	J	3.48	0.83	4.31	23.8 %
	A	3.29	0.82	4.11	24.8 %
	S	3.23	0.81	4.04	25.0 %
	O	3.14	0.74	3.88	23.6 %
	N	3.36	0.68	4.04	20.4 %
	D	3.47	0.69	4.16	20.0 %
2011	J	3.52	0.69	4.22	19.6 %
	F	3.68	0.63	4.31	17.2 %
	M	3.57	0.69	4.26	19.3 %
	A	3.61	0.70	4.31	19.4 %
	M	3.39	0.77	4.16	22.6 %
	J	3.25	0.79	4.04	24.3 %
	J	3.21	0.75	3.96	23.4 %
	A	2.82	0.82	3.63	29.0 %
	S	2.58	0.89	3.48	34.6 %
	O	2.65	0.88	3.54	33.3 %
	N	2.49	0.90	3.39	36.0 %
	D	2.34	0.90	3.24	38.5 %
2012	J	2.33	0.85	3.18	36.4 %
	F	2.37	0.86	3.23	36.4 %
	M	2.43	0.90	3.33	36.9 %
	A	2.41	0.93	3.34	38.8 %
	M	2.23	0.98	3.21	43.9 %
	J	2.08	1.01	3.09	48.7 %
	J	2.00	1.01	3.01	50.6 %
	A	2.14	0.96	3.10	45.0 %
	S	2.15	0.96	3.11	44.8 %
	O	2.14	0.98	3.12	45.6 %
	N	2.07	1.02	3.09	49.3 %
	D	2.11	1.02	3.12	48.3 %
2013	J	2.25	0.99	3.24	43.9 %
	F	2.33	1.00	3.33	42.8 %
	M	2.25	1.01	3.26	44.8 %
	A	2.07	1.04	3.11	50.3 %
	M	2.23	0.98	3.21	43.8 %
	J	2.52	0.96	3.49	38.1 %
	J	2.69	0.96	3.65	35.7 %
	A	2.87	0.98	3.85	34.2 %
	S	2.97	0.98	3.96	33.1 %
	O	2.85	0.98	3.83	34.5 %
	N	2.87	0.96	3.84	33.6 %
	D	2.98	0.89	3.87	30.0 %
2014	J	2.84	0.86	3.71	30.4 %
	F	2.75	0.86	3.61	31.1 %
	M	2.71	0.83	3.54	30.6 %
	A	2.66	0.83	3.49	31.2 %
	M	2.59	0.83	3.42	32.1 %
	J	2.58	0.81	3.39	31.3 %
	J	2.49	0.81	3.30	32.5 %
	A	2.36	0.83	3.19	35.1 %
	S	2.46	0.82	3.28	33.1 %
	O	2.31	0.87	3.19	37.8 %
	N	2.32	0.87	3.19	37.7 %
	D	2.16	0.87	3.03	40.0 %

Section:	Appendix 3.1 Appendix 3.4	Page No.:	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ..."

Consumers' Coalition observes in Appendix 3.4, page 1 of 6, that financing expense is the largest expense in Electrical operations in fiscal 2017 and is by 2022 is forecast to be greater than the sum of the next two expenses categories, operations and depreciation.

Consumers' Coalition observes that the 90 day T-bill interest rate forecasts in many recent years have forecast materially higher interest rates than those that actually occurred, and believes that this overstates the financial burdens to be faced by Manitoba Hydro, in past and current forecasts.

Consumers' Coalition has prepared the table below to attempt to quantify the error in forecasting of 90 day T-bill interest rate from data found in Economic Outlooks for 2006, 2007, 2009, 2010, 2011, 2012, 2013 and 2014. At the time this question was being prepared, Consumers' Coalition was unable to find a 2008 Economic Outlook. To allow for the final period comparison for each forecast, as there are approximately 6 weeks remaining in the fiscal year, Consumers' Coalition has estimated 0.89% as the 2014/15 actual value using the available Bank of Canada data series V39065 for the period April 1, 2014 to February 12, 2015. See cell 2014/15, in the row "Actual".

To assist in understanding the table, the 2011 first year error of 0.69% is calculated by subtracting the actual 2012 0.91% value from the forecast of 1.60%. The 8th year 2006

forecast error of 3.56% is calculated by subtracting the actual 2014 value of 0.94% from the 4.5% forecast for 2014.

90 Day T-bill	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fiscal year	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.00%	4.05%	4.25%	4.25%	4.30%	4.50%	4.50%	**4.50%**	4.50%
2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008									
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
2010					0.95%	2.50%	3.10%	3.65%	4.10%
2011						**1.60%**	2.80%	4.45%	3.80%
2012							1.00%	1.45%	2.95%
2013								1.05%	1.45%
2014									1.00%
Actual	4.16%	3.83%	1.84%	0.22%	0.78%	**0.91%**	0.97%	**0.94%**	0.89%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	**3.56%**	3.61%
2007	0.42%	2.41%	4.03%	3.47%	3.34%	3.28%	3.31%	3.36%	
2008									
2009	0.58%	1.12%	2.89%	3.23%	3.31%	3.36%			
2010	0.17%	1.59%	2.13%	2.71%	3.21%				
2011	**0.69%**	1.83%	3.51%	2.91%					
2012	0.03%	0.51%	2.06%						
2013	0.11%	0.56%							
2014	0.11%								
Avg error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42%	3.46%	3.61%
Avg Forecast	1.83%	2.63%	3.80%	4.03%	4.23%	4.33%	4.38%	4.38%	4.50%
Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

The average forecast is calculated using forecasts for periods of equal distance from the date of the forecast date. For the 2 year average, they include the second left side value in each row, from 4.05% for the 2006 forecast through to 1.45% for the 2013 forecast. For the 7 year value the average forecast includes the 2006 forecast for the 2012/13 fiscal year of 4.50% and the 2007 forecast for the 2013/14 fiscal year of 4.25% and would include the 2008 forecast for the 2014/15 fiscal year, had that forecast been available at the time of the calculation. The average error to average forecast is calculated by division.

QUESTION:

a) Please confirm that the data points extracted from the 2006, 2007 and 2009 through 2014 Economic Outlooks are correct for each of the fiscal periods or supply the corrected value for any erroneous data points.

c) Please update the table to incorporate the 2008 Economic Outlook 90 day T-bill interest rate forecasts, and provide the error calculation, using the methodology applied to develop the other fiscal year forecast error numbers.

g) To assist the Board in understanding the financial magnitude of the errors of forecasting of 90 day T-bill rates, please provide a table setting out the short term, floating rate long term debt, and fixed rate long term debt, in dollars and in percentage of total debt, for the 2012/13 and 2013/14 year ends, and the forecast year ends up to and including 2023/24.

RATIONALE FOR QUESTION:

The question goes to alleged forecast bias of an important element of the rate.

RESPONSE:

This information request's preamble, question and rationale make an unfounded allegation that Manitoba Hydro's interest rate forecasting methodology is biased and that it overstates the burdens to be faced by Manitoba Hydro in past and current forecasts. The information request also makes the supposition that the Corporation's only financial exposure to changing economic conditions is through changing interest rates and their potential impact on the Corporation's gross interest expense. These allegations and suppositions are false.

As Manitoba Hydro has stated in response to PUB/MH-I-10b, Manitoba Hydro operates in a complex economic environment that simultaneously affects many parts of its operations. The economy's impact on Manitoba Hydro's revenue requirement is not exclusively seen through changing interest rates and the evolving views of Manitoba Hydro's external interest rate forecasters. There are numerous counterbalances.

Forecast variances are a function of changing economic conditions, and not as a result of the methodology whereby Manitoba Hydro gathers its externally produced forecasts. Manitoba Hydro's interest rate forecast is unbiased, as it is not developed with the intent of selecting or encouraging one outcome over others. Forecaster opinions do change through time in response to changing market conditions. Although economic forecasts during the last few years have generally called for a quicker economic recovery and correspondingly higher interest rates, on an actual basis, the strength and pace of a recovery has been subdued. As the external forecasts have evolved through time, the Corporation's interest rate forecasting methodology has gathered and combined their opinions in an unbiased manner. The existing forecasting methodology provides a representative interest rate forecast at the time that it is produced. To remain current to changing conditions, the Corporation monitors financial markets on an ongoing basis, and reviews its interest rate forecasts at regular intervals throughout the year.

These regular updates to the interest rate forecast provide assurance that Manitoba Hydro's ratepayers will not be burdened by deviations from the long-term interest rate forecast. Manitoba Hydro's rates are set under a rigorous cost of service methodology (and not a rate-base rate of return approach), where the retained earnings and net income of Manitoba Hydro are held for the benefit of ratepayers. To the extent that interest costs are higher or lower than forecast, the difference, along with all other differences, flows to retained earnings. Retained earnings are not distributed as dividends to private shareholders (as may be the case in jurisdictions with a rate-base rate of return methodology) or used for any purpose other than managing the risks and revenue requirements on behalf of Manitoba Hydro's customers. To the extent that there are higher contributions to retained earnings as a result of this difference, there will be lower future rate increase requirements. Manitoba Hydro views this self-correcting mechanism at each GRA to be no different than the impact on earnings of weather or any other revenue or expense variable.

In the preamble, the Coalition prepared a table that attempted to quantify the forecast interest rate variances. The forecast variances are self-correcting at each GRA along with other counterbalancing factors and updates. As requested, Manitoba Hydro has provided the 2008 Economic Outlook data and reviewed the data points extracted from the 2006, 2007 and 2009 through 2014 Economic Outlooks. Note that the 2013/14 value in the 2011 forecast should be 3.45%, rather than 4.45%. Also note that the values reported in the Economic Outlooks are published in the spring of every year are not always the basis of the relevant year's IFF or revenue requirement.

90 Day T-bill	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fiscal year	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.00%	4.05%	4.25%	4.25%	4.30%	4.50%	4.50%	4.50%	4.50%
2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008			3.40%	3.95%	4.50%	4.50%	4.50%	4.50%	4.50%
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
2010					0.95%	2.50%	3.10%	3.65%	4.10%
2011						1.60%	2.80%	3.45%	3.80%
2012							1.00%	1.45%	2.95%
2013								1.05%	1.45%
2014									1.00%
Actual	4.16%	3.83%	1.84%	0.22%	0.78%	0.91%	0.97%	0.94%	0.89%

Variance	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	3.56%	3.61%
2007	0.42%	2.41%	4.03%	3.47%	3.34%	3.28%	3.31%	3.36%	
2008	1.56%	3.73%	3.72%	3.59%	3.53%	3.56%			
2009	0.58%	1.12%	2.89%	3.23%	3.31%	3.36%			
2010	0.17%	1.59%	2.13%	2.71%	3.21%				
2011	0.69%	1.83%	3.51%	2.91%					
2012	0.03%	0.51%	2.06%						
2013	0.11%	0.56%							
2014	0.11%								
Avg variance	0.39%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42%	3.46%	3.61%
Avg Forecast	2.01%	2.79%	3.76%	4.11%	4.28%	4.38%	4.42%	4.38%	4.50%
Variance/AvgFcst	19%	42%	76%	80%	78%	78%	77%	79%	80%

As requested in part g) of this Information Request, the following schedule provides Manitoba Hydro's actual and forecasted proportions of short term debt, floating rate long term debt, and fixed rate long term debt at March 31, 2013 – 2024.

Consolidated Debt Portfolio Summary
(By proportion of short term debt, floating rate long term debt, and fixed rate long term debt)

Actuals are to December 31, 2014; with forecast information for March 31, 2015 - 2024
($ in CAD millions)

Fiscal Year Ending	Short Term Debt		Floating Rate Long Term Debt		Fixed Rate Long Term Debt		Total Debt
	$	% of Total	$	% of Total	$	% of Total	$
March 31, 2013	-	0.0 %	1,604	16.0 %	8,406	84.0 %	10,010
March 31, 2014	-	0.0 %	2,127	19.3 %	8,881	80.7 %	11,009
March 31, 2015 *	83	0.7 %	1,812	14.8 %	10,345	84.5 %	12,240
March 31, 2016 *	142	1.0 %	1,995	13.8 %	12,278	85.2 %	14,415
March 31, 2017 *	55	0.3 %	2,311	13.4 %	14,828	86.2 %	17,194
March 31, 2018 *	111	0.6 %	2,696	13.4 %	17,312	86.0 %	20,120
March 31, 2019 *	134	0.6 %	3,374	15.5 %	18,235	83.9 %	21,743
March 31, 2020 *	74	0.3 %	3,541	15.4 %	19,329	84.2 %	22,944
March 31, 2021 *	7	0.0 %	3,661	15.5 %	19,959	84.5 %	23,627
March 31, 2022 *	40	0.2 %	3,781	16.1 %	19,720	83.8 %	23,542
March 31, 2023 *	145	0.6 %	3,440	14.5 %	20,200	84.9 %	23,786
March 31, 2024 *	152	0.6 %	3,560	14.8 %	20,380	84.6 %	24,092

* The forecasted debt percentages will be affected by the simplifying modeling assumption of a 20 year term to maturity for all new debt issuance. Actual terms to maturity will vary from forecast.

Section:	Appendix 3.1 Appendix 3.4	Page No.:	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ..."

Consumers' Coalition observes in Appendix 3.4, page 1 of 6, that financing expense is the largest expense in Electrical operations in fiscal 2017 and is by 2022 is forecast to be greater than the sum of the next two expenses categories, operations and depreciation.

Consumers' Coalition observes that the 90 day T-bill interest rate forecasts in many recent years have forecast materially higher interest rates than those that actually occurred, and believes that this overstates the financial burdens to be faced by Manitoba Hydro, in past and current forecasts.

Consumers' Coalition has prepared the table below to attempt to quantify the error in forecasting of 90 day T-bill interest rate from data found in Economic Outlooks for 2006, 2007, 2009, 2010, 2011, 2012, 2013 and 2014. At the time this question was being prepared, Consumers' Coalition was unable to find a 2008 Economic Outlook. To allow for the final period comparison for each forecast, as there are approximately 6 weeks remaining in the fiscal year, Consumers' Coalition has estimated 0.89% as the 2014/15 actual value using the available Bank of Canada data series V39065 for the period April 1, 2014 to February 12, 2015. See cell 2014/15, in the row "Actual".

To assist in understanding the table, the 2011 first year error of 0.69% is calculated by subtracting the actual 2012 0.91% value from the forecast of 1.60%. The 8th year 2006

forecast error of 3.56% is calculated by subtracting the actual 2014 value of 0.94% from the 4.5% forecast for 2014.

90 Day T-bill	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fiscal year	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.00%	4.05%	4.25%	4.25%	4.30%	4.50%	4.50%	**4.50%**	4.50%
2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008									
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
2010					0.95%	2.50%	3.10%	3.65%	4.10%
2011						**1.60%**	2.80%	4.45%	3.80%
2012							1.00%	1.45%	2.95%
2013								1.05%	1.45%
2014									1.00%
Actual	4.16%	3.83%	1.84%	0.22%	0.78%	**0.91%**	0.97%	**0.94%**	0.89%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	**3.56%**	3.61%
2007	0.42%	2.41%	4.03%	3.47%	3.34%	3.28%	3.31%	3.36%	
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2009	0.58%	1.12%	2.89%	3.23%	3.31%	3.36%			
2010	0.17%	1.59%	2.13%	2.71%	3.21%				
2011	**0.69%**	1.83%	3.51%	2.91%					
2012	0.03%	0.51%	2.06%						
2013	0.11%	0.56%							
2014	0.11%								
Avg error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42%	3.46%	3.61%
Avg Forecast	1.83%	2.63%	3.80%	4.03%	4.23%	4.33%	4.38%	4.38%	4.50%
Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

The average forecast is calculated using forecasts for periods of equal distance from the date of the forecast date. For the 2 year average, they include the second left side value in each row, from 4.05% for the 2006 forecast through to 1.45% for the 2013 forecast. For the 7 year value the average forecast includes the 2006 forecast for the 2012/13 fiscal year of 4.50% and the 2007 forecast for the 2013/14 fiscal year of 4.25% and would include the 2008 forecast for the 2014/15 fiscal year, had that forecast been available at the time of the calculation. The average error to average forecast is calculated by division.

QUESTION:

Please place on the record the equivalent to page A-1 of the 2014 Economic Outlook taken from each of the Economic Outlooks for the years 2006 through 2013.

RATIONALE FOR QUESTION:

The question goes to alleged forecast bias of an important element of the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	Page No.:	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ..."

Consumers' Coalition observes in Appendix 3.4, page 1 of 6, that financing expense is the largest expense in Electrical operations in fiscal 2017 and is by 2022 is forecast to be greater than the sum of the next two expenses categories, operations and depreciation.

Consumers' Coalition observes that the 90 day T-bill interest rate forecasts in many recent years have forecast materially higher interest rates than those that actually occurred, and believes that this overstates the financial burdens to be faced by Manitoba Hydro, in past and current forecasts.

Consumers' Coalition has prepared the table below to attempt to quantify the error in forecasting of 90 day T-bill interest rate from data found in Economic Outlooks for 2006, 2007, 2009, 2010, 2011, 2012, 2013 and 2014. At the time this question was being prepared, Consumers' Coalition was unable to find a 2008 Economic Outlook. To allow for the final period comparison for each forecast, as there are approximately 6 weeks remaining in the fiscal year, Consumers' Coalition has estimated 0.89% as the 2014/15 actual value using the available Bank of Canada data series V39065 for the period April 1, 2014 to February 12, 2015. See cell 2014/15, in the row "Actual".

To assist in understanding the table, the 2011 first year error of 0.69% is calculated by subtracting the actual 2012 0.91% value from the forecast of 1.60%. The 8th year 2006

forecast error of 3.56% is calculated by subtracting the actual 2014 value of 0.94% from the 4.5% forecast for 2014.

90 Day T-bill	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fiscal year	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.00%	4.05%	4.25%	4.25%	4.30%	4.50%	4.50%	**4.50%**	4.50%
2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008									
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
2010					0.95%	2.50%	3.10%	3.65%	4.10%
2011						**1.60%**	2.80%	4.45%	3.80%
2012							1.00%	1.45%	2.95%
2013								1.05%	1.45%
2014									1.00%
Actual	4.16%	3.83%	1.84%	0.22%	0.78%	**0.91%**	0.97%	**0.94%**	0.89%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	**3.56%**	3.61%
2007	0.42%	2.41%	4.03%	3.47%	3.34%	3.28%	3.31%	3.36%	
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2010	0.17%	1.59%	2.13%	2.71%	3.21%				
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2012	0.03%	0.51%	2.06%						
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2014	0.11%								
Avg error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42%	3.46%	3.61%
Avg Forecast	1.83%	2.63%	3.80%	4.03%	4.23%	4.33%	4.38%	4.38%	4.50%
Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

The average forecast is calculated using forecasts for periods of equal distance from the date of the forecast date. For the 2 year average, they include the second left side value in each row, from 4.05% for the 2006 forecast through to 1.45% for the 2013 forecast. For the 7 year value the average forecast includes the 2006 forecast for the 2012/13 fiscal year of 4.50% and the 2007 forecast for the 2013/14 fiscal year of 4.25% and would include the 2008 forecast for the 2014/15 fiscal year, had that forecast been available at the time of the calculation. The average error to average forecast is calculated by division.

QUESTION:

Since it appears that no recent forecast for 90 day T-bill interest rates has accurately approximated the actual interest rate at a time more than 3 years from the forecast, please provide any Economic Outlook since 1995 which accurately forecast the 90 day T-bill interest rate in any year, 3 or more years after the time of the forecast, and the intervening Economic Outlook forecasts, not already part of the record in this proceeding.

RATIONALE FOR QUESTION:

The question goes to alleged forecast bias of an important element of the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	**Page No.:**	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

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In its letter to the PUB on February 4, Manitoba Hydro indicated that “... more weight should be afforded to reviewing the first 10 years of the financial forecast ...”

Consumers’ Coalition observes in Appendix 3.4, page 1 of 6, that financing expense is the largest expense in Electrical operations in fiscal 2017 and is by 2022 is forecast to be greater than the sum of the next two expenses categories, operations and depreciation.

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forecast error of 3.56% is calculated by subtracting the actual 2014 value of 0.94% from the 4.5% forecast for 2014.

90 Day T-bill	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fiscal year	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.00%	4.05%	4.25%	4.25%	4.30%	4.50%	4.50%	**4.50%**	4.50%
2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008									
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
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2012							1.00%	1.45%	2.95%
2013								1.05%	1.45%
2014									1.00%
Actual	4.16%	3.83%	1.84%	0.22%	0.78%	**0.91%**	0.97%	**0.94%**	0.89%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	**3.56%**	3.61%
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QUESTION:

In light of the appearance that for 90 day T-bill interest rate forecasts for the fourth year and years thereafter are more than 300 basis points on average greater than the actual 90 day T-bill interest rate, please discuss the rationale, if any, for continuing to use this statistically biased and inaccurate forecast methodology for periods longer than four years

RATIONALE FOR QUESTION:

The question goes to alleged forecast bias of an important element of the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	Page No.:	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
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forecast error of 3.56% is calculated by subtracting the actual 2014 value of 0.94% from the 4.5% forecast for 2014.

90 Day T-bill Fiscal year	2006 2007	2007 2008	2008 2009	2009 2010	2010 2011	2011 2012	2012 2013	2013 2014	2014 2015
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2007		4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
2008									
2009				0.80%	1.90%	3.80%	4.20%	4.25%	4.25%
2010					0.95%	2.50%	3.10%	3.65%	4.10%
2011						**1.60%**	2.80%	4.45%	3.80%
2012							1.00%	1.45%	2.95%
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Actual	4.16%	3.83%	1.84%	0.22%	0.78%	**0.91%**	0.97%	**0.94%**	0.89%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	-0.16%	0.22%	2.41%	4.03%	3.52%	3.59%	3.53%	**3.56%**	3.61%
2007	0.42%	2.41%	4.03%	3.47%	3.34%	3.28%	3.31%	3.36%	
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QUESTION:

Please provide any statistical evidence that the Board should have any confidence in the proposition that “the proposed 3.95% rate increases” really are “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” in light of the statistically biased and inaccurate 90 day T-bill longer term interest rate forecasts. [Emphasis added]

RATIONALE FOR QUESTION:

The question goes to alleged forecast bias of an important element of the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	**Page No.:**	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that “... more weight should be afforded to reviewing the first 10 years of the financial forecast ...”

CONSUMERS’ COALITION observes in Appendix 3.4, that financing expense is the largest expense in Electrical operations in fiscal 2017 and is by 2022 is forecast to be greater than the sum of the next two expenses categories, operations and depreciation.

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To assist in understanding the table, the 2007 sixth year error of 3.82% is calculated by subtracting the 2013 actual 2.18% value from the forecast of 6%. The 4th year 2009 error of 3.22% is calculated by subtracting the 2013 actual value of 2.18% from the 5.4% forecast.

The average forecast is calculated using forecasts for periods of equal distance from the date of the forecast date. For 2006, they include the first left side value in each row, from 4.8% through to 3.25%. For the 9 year value it is the 2006 forecast for the 2014/15 fiscal year

10 year +	2006 2007	2007 2008	2008 2009	2009 2010	2010 2011	2011 2012	2012 2013	2013 2014	2014 2015
2006	4.80%	5.05%	5.30%	5.55%	5.80%	6.00%	6.00%	6.00%	6.00%
2007		4.40%	4.90%	5.30%	5.50%	5.65%	**6.00%**	6.00%	6.00%
2008									
2009				3.15%	3.80%	4.95%	**5.40%**	5.50%	5.50%
2010					4.00%	4.40%	4.65%	4.95%	5.30%
2011						3.80%	4.25%	4.45%	4.80%
2012							2.65%	3.00%	3.95%
2013								2.50%	3.05%
2014									3.25%
Actual	4.23%	4.24%	3.66%	3.89%	3.48%	2.83%	**2.18%**	2.70%	2.35%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	0.57%	0.81%	1.64%	1.66%	2.32%	3.17%	3.82%	3.30%	3.66%
2007	0.16%	1.24%	1.41%	2.02%	2.82%	**3.82%**	3.30%	3.66%	
2008									
2009	-0.74%	0.32%	2.12%	**3.22%**	2.80%	3.16%			
2010	0.52%	1.57%	2.47%	2.25%	2.96%				
2011	0.97%	2.12%	1.79%	2.46%					
2012	0.47%	0.34%	1.61%						
2013	-0.20%	0.71%							
2014	0.91%								
Avg Error	0.33%	1.01%	1.84%	2.32%	2.72%	3.38%	3.56%	3.48%	3.66%
Avg Forecast	3.57%	4.06%	4.77%	5.24%	5.56%	5.83%	6.00%	6.00%	6.00%
AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

QUESTION:

a) Please confirm that the data points extracted from the 2006, 2007 and 2009 through 2014 Economic Outlooks are correct for each of the fiscal periods or supply the corrected value for any erroneous data points.

c) Please update the table to incorporate the 2008 Economic Outlook 10 Year + interest rate forecasts, and provide the error calculation, using the methodology applied to develop the other fiscal year forecast error numbers.

RATIONALE FOR QUESTION:

Goes to an alleged forecast bias which is central to the rate.

RESPONSE:

This information request's preamble, question and rationale make an unfounded allegation that Manitoba Hydro's interest rate forecasting methodology is biased and that it overstates the burdens to be faced by Manitoba Hydro in past and current forecasts. The information request also makes the supposition that the Corporation's only financial exposure to changing economic conditions is through changing interest rates and their potential impact on the Corporation's gross interest expense. These allegations and suppositions are false.

As Manitoba Hydro has stated in response to PUB/MH-I-10b, Manitoba Hydro operates in a complex economic environment that simultaneously affects many parts of its operations. The economy's impact on Manitoba Hydro's revenue requirement is not exclusively seen through changing interest rates and the evolving views of Manitoba Hydro's external interest rate forecasters. There are numerous counterbalances.

Forecast variances are a function of changing economic conditions, and not as a result of the methodology whereby Manitoba Hydro gathers its externally produced forecasts. Manitoba Hydro's interest rate forecast is unbiased, as it is not developed with the intent of selecting or encouraging one outcome over others. Forecaster opinions do change through time in response to changing market conditions. Although economic forecasts during the last few years have generally called for a quicker economic recovery and correspondingly higher interest rates, on an actual basis, the strength and pace of a recovery has been subdued. As the external forecasts have evolved through time, the Corporation's interest rate forecasting methodology has gathered and combined their opinions in an unbiased manner. The existing forecasting methodology provides a representative interest rate forecast at the time that it is produced. To remain current to changing conditions, the Corporation monitors financial markets on an ongoing basis, and reviews its interest rate forecasts at regular intervals throughout the year.

These regular updates to the interest rate forecast provide assurance that Manitoba Hydro’s ratepayers will not be burdened by deviations from the long-term interest rate forecast. Manitoba Hydro’s rates are set under a rigorous cost of service methodology (and not a rate-base rate of return approach), where the retained earnings and net income of Manitoba Hydro are held for the benefit of ratepayers. To the extent that interest costs are higher or lower than forecast, the difference, along with all other differences, flows to retained earnings. Retained earnings are not distributed as dividends to private shareholders (as may be the case in jurisdictions with a rate-base rate of return methodology) or used for any purpose other than managing the risks and revenue requirements on behalf of Manitoba Hydro’s customers. To the extent that there are higher contributions to retained earnings as a result of this difference, there will be lower future rate increase requirements. Manitoba Hydro views this self-correcting mechanism at each GRA to be no different than the impact on earnings of weather or any other revenue or expense variable.

In the preamble, the Coalition prepared a table that attempted to quantify the forecast interest rate variances. The forecast variances are self-correcting at each GRA along with other counterbalancing factors and updates. As requested, Manitoba Hydro has provided the 2008 Economic Outlook data and reviewed the data points extracted from the 2006, 2007 and 2009 through 2014 Economic Outlooks. Also note that the values reported in the Economic Outlooks are published in the spring of every year are not always the basis of the relevant year’s IFF or revenue requirement.

	2006	2007	2008	2009	2010	2011	2012	2013	2014
10 year +	2007	2008	2009	2010	2011	2012	2013	2014	2015
2006	4.80%	5.05%	5.30%	5.55%	5.80%	6.00%	6.00%	6.00%	6.00%
2007		4.40%	4.90%	5.30%	5.50%	5.65%	6.00%	6.00%	6.00%
2008			4.15%	4.70%	5.25%	5.35%	5.65%	5.85%	5.85%
2009				3.15%	3.80%	4.95%	5.40%	5.50%	5.50%
2010					4.00%	4.40%	4.65%	4.95%	5.30%
2011						3.80%	4.25%	4.45%	4.80%
2012							2.65%	3.00%	3.95%
2013								2.50%	3.05%
2014									3.25%
Actual	4.23%	4.24%	3.66%	3.89%	3.48%	2.83%	2.18%	2.70%	2.35%

Variance	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
2006	0.57%	0.81%	1.64%	1.66%	2.32%	3.17%	3.82%	3.30%	3.65%
2007	0.16%	1.24%	1.41%	2.02%	2.82%	3.82%	3.30%	3.65%	
2008	0.49%	0.81%	1.77%	2.52%	3.47%	3.15%	3.50%		
2009	-0.74%	0.32%	2.12%	3.22%	2.80%	3.15%			
2010	0.52%	1.57%	2.47%	2.25%	2.95%				
2011	0.97%	2.07%	1.75%	2.45%					
2012	0.47%	0.30%	1.60%						
2013	-0.20%	0.70%							
2014	0.90%								
Avg Variance	0.35%	0.98%	1.82%	2.35%	2.87%	3.32%	3.54%	3.48%	3.65%
Avg Forecast	3.63%	4.14%	4.84%	5.26%	5.58%	5.84%	5.95%	6.00%	6.00%
AvgVariance/AvgFcst	10%	24%	38%	45%	51%	57%	59%	58%	61%

Section:	Appendix 3.1 Appendix 3.4	**Page No.:**	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

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Consumers’ Coalition has prepared the table below to attempt to quantify the error in forecasting of 10 year + rates from data found in Economic Outlooks for 2006, 2007, 2009, 2010, 2011, 2012, 2013 and 2014. At the time this question was being prepared, Consumers’ Coalition was unable to find a 2008 Economic Outlook. To allow for the final period comparison for each forecast, as there are approximately 6 weeks remaining in the fiscal year, Consumers’ Coalition has estimated 2.35% as the 2014/15 actual value using the available Bank of Canada data series V39055 and V39056 for the period April 1, 2014 to February 12, 2015. See cell 2014/15, in the row “Actual”.

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The average forecast is calculated using forecasts for periods of equal distance from the date of the forecast date. For 2006, they include the first left side value in each row, from 4.8% through to 3.25%. For the 9 year value it is the 2006 forecast for the 2014/15 fiscal year

10 year +	2006 2007	2007 2008	2008 2009	2009 2010	2010 2011	2011 2012	2012 2013	2013 2014	2014 2015
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Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
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AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

QUESTION:

Please place on the record the equivalent to page A-1 of the 2014 Economic Outlook taken from each of the Economic Outlooks for the years 2006 through 2013.

RATIONALE FOR QUESTION:

Goes to an alleged forecast bias which is central to the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	Page No.:	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
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2009				3.15%	3.80%	4.95%	**5.40%**	5.50%	5.50%
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Actual	4.23%	4.24%	3.66%	3.89%	3.48%	2.83%	**2.18%**	2.70%	2.35%

Error	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
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Avg Forecast	3.57%	4.06%	4.77%	5.24%	5.56%	5.83%	6.00%	6.00%	6.00%
AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

QUESTION:

Since it appears that no recent forecast for 10 Year + interest rates has accurately approximated the actual interest rate at a time more than 4 years from the forecast, please provide any Economic Outlook since 1995 which accurately forecast the 10 year + interest rate in any year 4 or more years after the time of the forecast, and the intervening Economic Outlook forecasts, not already part of the record in this proceeding.

RATIONALE FOR QUESTION:

Goes to an alleged forecast bias which is central to the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.4	**Page No.:**	Page A-1 Fiscal Year Basis Page 1 of 6
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
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QUESTION:

In light of the appearance that 10 Year + interest rate forecasts for the sixth year and years thereafter are more than double the actual, and there are material variances occurring as by the third forecast year, please discuss the rationale, if any, for continuing to use this statistically biased and inaccurate forecast methodology for periods longer than two years, particularly during a period in which billions of dollars of investments are being forecast.

RATIONALE FOR QUESTION:

Goes to an alleged forecast bias which is central to the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

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Section:	Appendix 3.1 Appendix 3.4	**Page No.:**	Page A-1 Fiscal Year Basis Page 1 of 6
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2010	0.52%	1.57%	2.47%	2.25%	2.96%				
2011	0.97%	2.12%	1.79%	2.46%					
2012	0.47%	0.34%	1.61%						
2013	-0.20%	0.71%							
2014	0.91%								
Avg Error	0.33%	1.01%	1.84%	2.32%	2.72%	3.38%	3.56%	3.48%	3.66%
Avg Forecast	3.57%	4.06%	4.77%	5.24%	5.56%	5.83%	6.00%	6.00%	6.00%
AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

QUESTION:

Please provide any statistical evidence that the Board should have any confidence in the proposition that "the proposed 3.95% rate increases" really are "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" in light of the statistically biased and inaccurate 10 Year + interest rate longer term forecasts. [Emphasis added]

RATIONALE FOR QUESTION:

Goes to an alleged forecast bias which is central to the rate.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.3 Appendix 11.41	**Page No.:**	Figure 13.1 page 17 Pages 2, 3 and 4 of 4
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

In its letter to the PUB on February 4, Manitoba Hydro indicated that "... more weight should be afforded to reviewing the first 10 years of the financial forecast ..."

Consumers' Coalition observes in Appendix 3.3 in Figure 13-1 that Manitoba Hydro has provided a chart showing amounts of debt refinancing in fiscal years from 2015 to 2024.

Consumers' Coalition observes in Appendix 11.41 at page 4 of 4 that Manitoba Hydro has provided two charts showing amounts of debt maturing on the basis of "maturity dates as per financial statements" and on the basis of "action dates for physical debt".

In Appendix 3.3 Figure 13-1 appears to indicate approximately $750 million of debt refinancing, while Appendix 11.41 appears to indicate approximately $1,000 million of debt with "maturity dates as per financial statements" and approximately $1,500 million of debt with a 2019 "action" date.

In Appendix 3.3 Manitoba Hydro identifies a policy that applies to "fixed rate debt to be refinanced" within a 12 month period.

QUESTION:

a) To allow a more precise understanding of the data in the 2 charts on page 4 of 4 in Appendix 11.41, please reproduce the charts after reducing the CAD dollar axis range to span zero to 2 billion.

b) Please reconcile the debt instruments in the approximate $750 million of the debt instruments in Figure 13.1 to be refinanced in 2019, to the $1,000 million of debt with "maturity dates as per financial statements" in 2019 in Appendix 11.41, and approximately $1,500 million of debt with a 2019 "action" date.

c) Please define "debt to be refinanced" as it is used in describing the policy on page 17 of Appendix 3.3, and contrast that term with debt with "maturity dates as per financial statements".

d) Please contrast the concept of "debt to be refinanced", as it is used in describing the policy on page 17 of Appendix 3.3, with debt with an "action" date. Does the defination of an action date exclude a maturity date.

e) If debt initially issued with a floating rate interest obligation, and at some an "action" date could be used at the basis for a long term floating to fixed rate interest swap, should that not be treated as "fixed rate debt to be refinanced"

f) For the approximate $250 million of the debt instruments with "maturity dates as per financial statements" in 2019 in Appendix 11.41 not included in the $750 million of the debt instruments in Figure 13.1 to be refinanced in 2019, please explain in what way, if any, their treatment in the forecast differs from a debt instrument to be refinanced at either floating or long term fixed rates.

g) For the approximate $500 million of the debt instruments with a 2019 "action" date not included in the "maturity dates as per financial statements" in 2019 in Appendix 11.41 not included in the $1,000 million of debt with "maturity dates as per financial statements" in 2019 in Appendix 11.41, please explain in what way, if any, their treatment in the forecast differs from a debt instrument to be refinanced at either floating or long term fixed rates.

RATIONALE FOR QUESTION:

Seeks clarification on issues important to the financial forecast and rates.

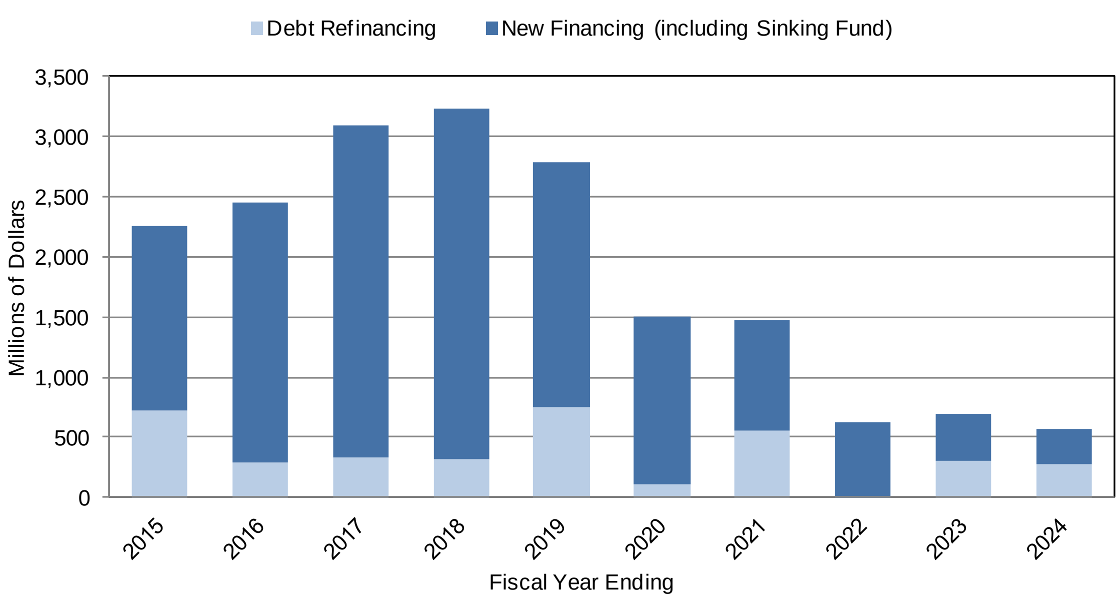
RESPONSE:

The following answer is the response to COALITION/MH-I-109(a)-(g):

The projected consolidated borrowing requirements chart shown in IFF14 (Appendix 3.3, Figure 13.1) and the two debt maturity charts shown in Appendix 11.41 differ due to:

a) varying cutoff dates (the IFF14 chart is at October 31, 2014 while the Appendix 11.41 charts are at December 31, 2014);
b) the IFF14 chart is net of sinking fund withdrawals while the Appendix 11.41 charts depicts long term debt maturities before any sinking fund withdrawals; and
c) the second chart in Appendix 11.41 depicts the portfolio's long term debt maturities at the earliest action dates for a debt series.

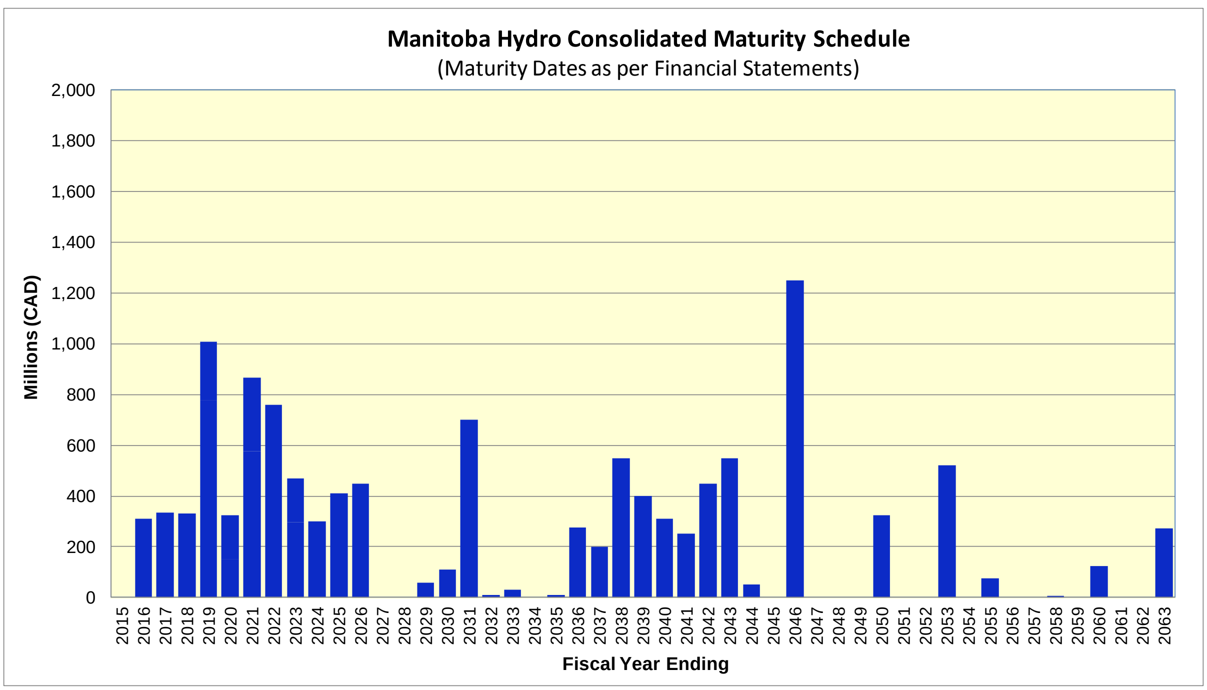
The IFF14 chart, depicting the projected consolidated borrowing requirements, is as follows:



As described in Appendix 11.41, in accordance with accounting standards, the Corporation's financial statement presentation for debt maturities specifies the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates). This financial statement presentation is also adopted for the IFF. The IFF14 chart (with an October 31, 2014 cutoff date) also shows the forecasted debt refinancings net of forecasted sinking fund withdrawals. New financings include forecasted cash requirements to fund sinking fund contributions.

The total debt requirements for Manitoba Hydro's electric operations in the next five year period will peak at levels in excess of $3 billion per year. The debt maturity charts depicted in Appendix 11.41 had the vertical axis extended to $4 billion Canadian dollars (CAD) in order to provide a similar context to this IFF14 chart. As requested, the following charts from Appendix 11.41 have been depicted with the vertical axis up to $2 billion CAD.

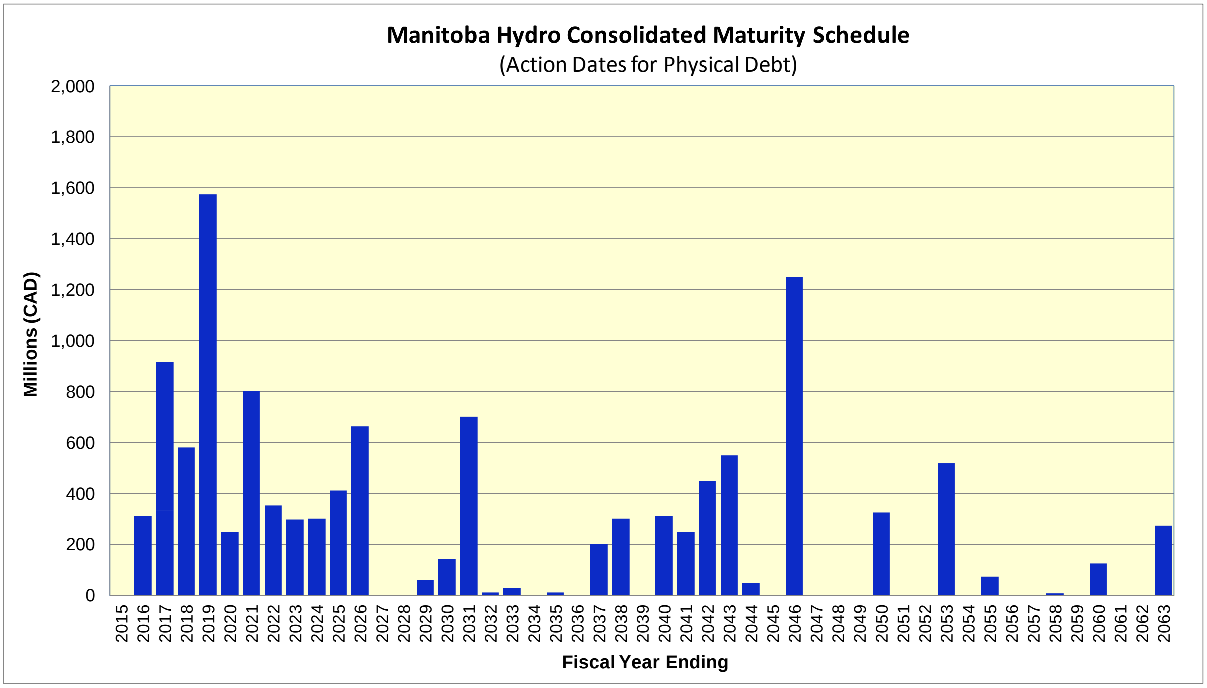
The first chart in Appendix 11.41, subtitled "Maturity Dates as per Financial Statements", depicted the long term debt maturities (at December 31, 2014) in accordance with financial statement presentation and before any sinking fund withdrawals.



Unlike the IFF14 chart, the charts in Appendix 11.41 were depicting debt maturities and not forecasted debt refinancings. For the 2018/19 fiscal year, the $1,008 million of debt maturities in the first Appendix 11.41 chart are $260 million higher than the $748 million refinancing amounts in the IFF14 chart in Figure 13.1 due to the projected $460 million sinking fund withdrawal for debt series EE and BU in 2018/19 (as valued at December 31, 2014), and less the $200 million underlying refinancing of debt series FC-3 that occurred between the October 31, 2014 IFF14 cutoff date and the December 31, 2014 dating for the

Appendix 11.41 charts (FC-3 had a December 3, 2014 action date and the debt streams now have later maturity dates than the June 2, 2018 swap maturity date).

The second chart from Appendix 11.41, subtitled “Action Dates for Physical Debt”, depicted the long term debt maturities of the physical debt within the debt portfolio (at December 31, 2014), including cases where the maturity of underlying physical debt is before the maturity of the linked forward interest rate swap for a debt series.



For the 2018/19 fiscal year, the $1,576 million debt maturities in the action date chart is $568 million CAD higher than the $1,008 million debt maturities in the first Appendix 11.41 chart due to the 2018/19 maturity of underlying physical debt on debt series C132-2A, C132-2B, GE-1, GE-2 and GE-3. If existing floating rate debt is used as underlying debt for a fixed interest rate swap, then the floating rate debt would be reclassified as fixed rate debt at the linked date. Although, debt series with linked interest rate swaps are subject to some interest rate risk in cases where the maturity of underlying physical debt is before the maturity of the linked forward interest rate swap for a debt series, the IFF assumes that debt terms on existing forward interest rate swaps will remain constant until their swap maturity dates.

Manitoba Hydro's interest rate risk policy and guidelines (see Appendix 3.3 page 17, or Appendix 3.7 page 9) are applicable to the existing debt portfolio. Although some of the long term debt issues may be retired at their maturity in accordance with the availability of sinking fund withdrawals and surplus cash, to be prudent and risk adverse, the policy and guideline measures consider the maximum interest rate exposure on the existing debt portfolio, and therefore assumes that all long term debt will be refinanced at their action and maturity dates.

Section:	Appendix 3.1 Appendix 3.2	**Page No.:**	Page A-1 and Fall Update Pages 2-4 & CIBC attachment
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers’ Coalition observes that the input data from many of the forecasters contained in the fall update has been superseded with the release on new forecasts by those forecasters. Consumers’ Coalition also notes that significant events have taken place in the financial markets, including the reduction of the Bank of Canada’s policy rate in January 2015. The table below compares CIBC Appendix 3.2 end period data to the January 29, 2015 CIBC end period forecast available through the internet.

			1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016
CIBC	18/09/2014	98 Day T-bill	1.00%	1.05%	1.20%	1.45%	1.45%	1.45%	1.40%	1.45%
CIBC	29/01/2015	98 Day T-bill	0.45%	0.45%	0.45%	0.50%	0.60%	0.80%	0.95%	1.00%
		Change	0.55%	0.60%	0.75%	0.95%	0.85%	0.65%	0.45%	0.45%
CIBC	18/09/2014	10 Year	2.70%	3.00%	3.05%	2.80%	2.75%	2.70%	2.75%	2.80%
CIBC	29/01/2015	10 Year	1.35%	1.70%	2.00%	2.00%	2.10%	2.40%	2.60%	2.65%
		Change	1.35%	1.30%	1.05%	0.80%	0.65%	0.30%	0.15%	0.15%
CIBC	18/09/2014	30 Year	3.40%	3.50%	3.55%	3.35%	3.25%	3.20%	3.25%	3.35%
CIBC	29/01/2015	30 Year	2.00%	2.35%	2.55%	2.70%	2.90%	2.95%	3.00%	3.05%
		Change	1.40%	0.65%	0.85%	0.90%	0.95%	1.00%	1.10%	1.10%

On a calendar year basis, Consumers’ Coalition estimates that the 98 day T-bill average rate for 2016 would have dropped by approximately 67 basis points, and that the 10 Year +

average interest rate would have dropped by approximately 70 basis points based on the changes in the CIBC forecasts from September 2014 to January 2015.

Consumers' Coalition observes that the change in the 90 day T-bill rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was only 30 basis points. Consumers' Coalition observes that the change in the 10 Year + rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was also 30 basis points, significantly less than the change in the CIBC forecasts for calendar 2016.

QUESTION:

Please confirm that the data points in the table above accurately compare the period end CIBC forecast rates for the maturities indicated and for the forecast dates identified.

RATIONALE FOR QUESTION:

Goes to the reliability of financial forecasts which are relevant to rate setting.

RESPONSE:

Manitoba Hydro confirms that all of the data points summarized in the table above for September 18, 2014 reflect the end-of-period forecasts of CIBC for the maturities indicated.

Manitoba Hydro confirms that all of the data points summarized in the table above for January 29, 2015 reflect the end-of-period forecasts of CIBC for the maturities indicated with the exception of the 10 year rate in Q1 2015. The 10 year rate in Q1 2015 in CIBC's January 29, 2015 forecast is 1.40% and not 1.35% as summarized above.

Section:	Appendix 3.1 Appendix 3.2	Page No.:	Page A-1 and Fall Update Pages 2-4 & CIBC attachment
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers’ Coalition observes that the input data from many of the forecasters contained in the fall update has been superseded with the release on new forecasts by those forecasters. Consumers’ Coalition also notes that significant events have taken place in the financial markets, including the reduction of the Bank of Canada’s policy rate in January 2015. The table below compares CIBC Appendix 3.2 end period data to the January 29, 2015 CIBC end period forecast available through the internet.

			1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016
CIBC	18/09/2014	98 Day T-bill	1.00%	1.05%	1.20%	1.45%	1.45%	1.45%	1.40%	1.45%
CIBC	29/01/2015	98 Day T-bill	0.45%	0.45%	0.45%	0.50%	0.60%	0.80%	0.95%	1.00%
		Change	0.55%	0.60%	0.75%	0.95%	0.85%	0.65%	0.45%	0.45%
CIBC	18/09/2014	10 Year	2.70%	3.00%	3.05%	2.80%	2.75%	2.70%	2.75%	2.80%
CIBC	29/01/2015	10 Year	1.35%	1.70%	2.00%	2.00%	2.10%	2.40%	2.60%	2.65%
		Change	1.35%	1.30%	1.05%	0.80%	0.65%	0.30%	0.15%	0.15%
CIBC	18/09/2014	30 Year	3.40%	3.50%	3.55%	3.35%	3.25%	3.20%	3.25%	3.35%
CIBC	29/01/2015	30 Year	2.00%	2.35%	2.55%	2.70%	2.90%	2.95%	3.00%	3.05%
		Change	1.40%	0.65%	0.85%	0.90%	0.95%	1.00%	1.10%	1.10%

On a calendar year basis, Consumers’ Coalition estimates that the 98 day T-bill average rate for 2016 would have dropped by approximately 67 basis points, and that the 10 Year +

average interest rate would have dropped by approximately 70 basis points based on the changes in the CIBC forecasts from September 2014 to January 2015.

Consumers' Coalition observes that the change in the 90 day T-bill rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was only 30 basis points. Consumers' Coalition observes that the change in the 10 Year + rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was also 30 basis points, significantly less than the change in the CIBC forecasts for calendar 2016.

QUESTION:

As your response is scheduled for the second week of March, please update the tables on page 2, 3 and 4 of 4 in Appendix 3.2 for the most recent interest rate forecasts available as at the end of February 2015.

RATIONALE FOR QUESTION:

Goes to the reliability of financial forecasts which are relevant to rate setting.

RESPONSE:

For the purpose of the first round of IR responses, Manitoba Hydro has provided an update of interest rate forecasts using the forecasting sources available around the end of January 2015 in the response to PUB/MH I-75c.

Section:	Appendix 3.1 Appendix 3.2	Page No.:	Page A-1 and Fall Update Pages 2-4 & CIBC attachment
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition observes that the input data from many of the forecasters contained in the fall update has been superseded with the release on new forecasts by those forecasters. Consumers' Coalition also notes that significant events have taken place in the financial markets, including the reduction of the Bank of Canada's policy rate in January 2015. The table below compares CIBC Appendix 3.2 end period data to the January 29, 2015 CIBC end period forecast available through the internet.

			1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016
CIBC	18/09/2014	98 Day T-bill	1.00%	1.05%	1.20%	1.45%	1.45%	1.45%	1.40%	1.45%
CIBC	29/01/2015	98 Day T-bill	0.45%	0.45%	0.45%	0.50%	0.60%	0.80%	0.95%	1.00%
		Change	0.55%	0.60%	0.75%	0.95%	0.85%	0.65%	0.45%	0.45%
CIBC	18/09/2014	10 Year	2.70%	3.00%	3.05%	2.80%	2.75%	2.70%	2.75%	2.80%
CIBC	29/01/2015	10 Year	1.35%	1.70%	2.00%	2.00%	2.10%	2.40%	2.60%	2.65%
		Change	1.35%	1.30%	1.05%	0.80%	0.65%	0.30%	0.15%	0.15%
CIBC	18/09/2014	30 Year	3.40%	3.50%	3.55%	3.35%	3.25%	3.20%	3.25%	3.35%
CIBC	29/01/2015	30 Year	2.00%	2.35%	2.55%	2.70%	2.90%	2.95%	3.00%	3.05%
		Change	1.40%	0.65%	0.85%	0.90%	0.95%	1.00%	1.10%	1.10%

On a calendar year basis, Consumers' Coalition estimates that the 98 day T-bill average rate for 2016 would have dropped by approximately 67 basis points, and that the 10 Year +

average interest rate would have dropped by approximately 70 basis points based on the changes in the CIBC forecasts from September 2014 to January 2015.

Consumers' Coalition observes that the change in the 90 day T-bill rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was only 30 basis points. Consumers' Coalition observes that the change in the 10 Year + rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was also 30 basis points, significantly less than the change in the CIBC forecasts for calendar 2016.

QUESTION:

As your response is scheduled for the second week of March, please update the tables in Appendix 3.4 for the most recent interest rate forecasts available as at the end of February 2015.

RATIONALE FOR QUESTION:

Goes to the reliability of financial forecasts which are relevant to rate setting.

RESPONSE:

Please see the responses to PUB/MH-I-10b and PUB/MH-I-75c which provides an update to the interest rate forecasts to January 2015 and the MH14 scenario incorporating this updated interest rate forecast.

Section:	Appendix 3.1 Appendix 3.2	**Page No.:**	Page A-1 and Fall Update Pages 2-4 & CIBC attachment
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers’ Coalition observes that the input data from many of the forecasters contained in the fall update has been superseded with the release on new forecasts by those forecasters. Consumers’ Coalition also notes that significant events have taken place in the financial markets, including the reduction of the Bank of Canada’s policy rate in January 2015. The table below compares CIBC Appendix 3.2 end period data to the January 29, 2015 CIBC end period forecast available through the internet.

			1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016
CIBC	18/09/2014	98 Day T-bill	1.00%	1.05%	1.20%	1.45%	1.45%	1.45%	1.40%	1.45%
CIBC	29/01/2015	98 Day T-bill	0.45%	0.45%	0.45%	0.50%	0.60%	0.80%	0.95%	1.00%
		Change	0.55%	0.60%	0.75%	0.95%	0.85%	0.65%	0.45%	0.45%
CIBC	18/09/2014	10 Year	2.70%	3.00%	3.05%	2.80%	2.75%	2.70%	2.75%	2.80%
CIBC	29/01/2015	10 Year	1.35%	1.70%	2.00%	2.00%	2.10%	2.40%	2.60%	2.65%
		Change	1.35%	1.30%	1.05%	0.80%	0.65%	0.30%	0.15%	0.15%
CIBC	18/09/2014	30 Year	3.40%	3.50%	3.55%	3.35%	3.25%	3.20%	3.25%	3.35%
CIBC	29/01/2015	30 Year	2.00%	2.35%	2.55%	2.70%	2.90%	2.95%	3.00%	3.05%
		Change	1.40%	0.65%	0.85%	0.90%	0.95%	1.00%	1.10%	1.10%

On a calendar year basis, Consumers’ Coalition estimates that the 98 day T-bill average rate for 2016 would have dropped by approximately 67 basis points, and that the 10 Year +

average interest rate would have dropped by approximately 70 basis points based on the changes in the CIBC forecasts from September 2014 to January 2015.

Consumers' Coalition observes that the change in the 90 day T-bill rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was only 30 basis points. Consumers' Coalition observes that the change in the 10 Year + rate for fiscal 2016/17 from page A-1 in the 2014 Economic Outlook to the Fall update page was also 30 basis points, significantly less than the change in the CIBC forecasts for calendar 2016.

QUESTION:

As your response is scheduled for the second week of March, please update the tables in Appendix 3.6 for the "-1% interest rate" scenario for the most recent interest rate forecasts available as at the end of February 2015.

RATIONALE FOR QUESTION:

Goes to the reliability of financial forecasts which are relevant to rate setting.

RESPONSE:

Sensitivities, such as the -1% interest rate scenario, are instructive in highlighting key risks that the Corporation faces and are not developed for the purpose of determining the Corporation's revenue requirement. As indicated in the response to PUB/MH-I-10b, interest rate scenarios would not occur in isolation of other economic outcomes that may affect the Corporation's financial performance, and therefore would not provide a representative update to the Corporation's revenue requirement.

Section:	Appendix 3.1 Appendix 3.2 Tab 5 Figure 5.8	**Page No.:**	Page A-1 and Fall Update Pages 1-4 & attachment Page 22 of 51
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition notes that in fiscal 2017/18, and other years a significant portion of interest is capitalized or allocated to construction, and as such the finance expense does not fully describe the cash burden of interest paid or accruing in each year.

As indicated in earlier questions, Consumers' Coalition believes, that for forecasts longer than 3 or more years, Manitoba Hydro's choice of inputs and longer term methodology lead to forecast rates which substantially overstate the actual market interest rates they are purporting to estimate. The table below provides the average forecast, the average error, and the ratio of the average error to the average forecast, estimated by Consumers' Coalition for the 10 Year +, and the 90 day T-bill rates and forecasts developed as part of an earlier question.

Error 10 Year +	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
Avg Error	0.33%	1.01%	1.84%	2.32%	2.72%	3.38%	3.56 %	3.48%	3.66%
Avg Fcst	3.57%	4.06%	4.77%	5.24%	5.56%	5.83%	6.00 %	6.00%	6.00%
AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

90 Day T-bill	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
Avg Error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42 %	3.46%	3.61%
Avg Fcst	1.83%	2.63%	3.80%	4.03%	4.23%	4.33%	4.38 %	4.38%	4.50%
Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

Consumers' Coalition is aware that another organization owned by the Province of Manitoba, Manitoba Public Insurance (MPI), in a recent regulatory proceeding proposed a "lower interest rate growth forecast" which was based on its standard interest rate forecast methodology, "but with forecasted interest rates increasing over ten years instead of five". [See page 8 of the GRA Overview in the MPI 2014 Rate Application]

Consumers' Coalition believes that the proposed MPI "lower interest rate growth forecast" might, by reducing the speed at which forecast interest rates were increased up to the 10th year, substantially lessen the forecasting error for both short term and long term rates that seems systemic in the Manitoba Hydro forecast methodology for longer periods.

While adopting a methodology similar to the MPI "lower interest rate growth forecast" might reduce the significant error seen in the second through fifth years of the forecast period, this methodology might not address the problem of the errors of massive proportion in the later years of the forecast.

Consumers' Coalition notes that it has not had the resources to test whether the MPI "lower interest rate growth forecast" assumption of a ten year period rather than five results in the most robust and accurate longer term forecast. Based on the significant error factors generated in years 8 and 9 of this analysis, it is probable that a linear deferral for a different

period, for example 15 or 20 years, might result in a more robust and accurate longer term forecast. Consumers' Coalition also notes that it is possible that a non-linear deferral methodology could result in a more robust and accurate longer term forecast. Consumers' Coalition also lacks access to the confidential and proprietary input forecasts relied upon by Manitoba Hydro as is as such unable to duplicate Manitoba Hydro's calculations.

QUESTION:

Please provide the numerical values supporting the 3 series presented in Figure 5.8.

RATIONALE FOR QUESTION:

Seeks to provide a more reliable estimate of short and medium term debt cost forecast, which is a major driver or rates.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.2 Tab 5 Figure 5.8	Page No.:	Page A-1 and Fall Update Pages 1-4 & attachment Page 22 of 51
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition notes that in fiscal 2017/18, and other years a significant portion of interest is capitalized or allocated to construction, and as such the finance expense does not fully describe the cash burden of interest paid or accruing in each year.

As indicated in earlier questions, Consumers' Coalition believes, that for forecasts longer than 3 or more years, Manitoba Hydro's choice of inputs and longer term methodology lead to forecast rates which substantially overstate the actual market interest rates they are purporting to estimate. The table below provides the average forecast, the average error, and the ratio of the average error to the average forecast, estimated by Consumers' Coalition for the 10 Year +, and the 90 day T-bill rates and forecasts developed as part of an earlier question.

Error 10 Year +	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
Avg Error	0.33%	1.01%	1.84%	2.32%	2.72%	3.38%	3.56%	3.48%	3.66%
Avg Fcst	3.57%	4.06%	4.77%	5.24%	5.56%	5.83%	6.00%	6.00%	6.00%
AvgEr/AvgFcst	9%	25%	39%	44%	49%	58%	59%	58%	61%

90 Day T-bill	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
Avg Error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42%	3.46%	3.61%
Avg Fcst	1.83%	2.63%	3.80%	4.03%	4.23%	4.33%	4.38%	4.38%	4.50%
Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

Consumers' Coalition is aware that another organization owned by the Province of Manitoba, Manitoba Public Insurance (MPI), in a recent regulatory proceeding proposed a "lower interest rate growth forecast" which was based on its standard interest rate forecast methodology, "but with forecasted interest rates increasing over ten years instead of five". [See page 8 of the GRA Overview in the MPI 2014 Rate Application]

Consumers' Coalition believes that the proposed MPI "lower interest rate growth forecast" might, by reducing the speed at which forecast interest rates were increased up to the 10th year, substantially lessen the forecasting error for both short term and long term rates that seems systemic in the Manitoba Hydro forecast methodology for longer periods.

While adopting a methodology similar to the MPI "lower interest rate growth forecast" might reduce the significant error seen in the second through fifth years of the forecast period, this methodology might not address the problem of the errors of massive proportion in the later years of the forecast.

Consumers' Coalition notes that it has not had the resources to test whether the MPI "lower interest rate growth forecast" assumption of a ten year period rather than five results in the most robust and accurate longer term forecast. Based on the significant error factors generated in years 8 and 9 of this analysis, it is probable that a linear deferral for a different

period, for example 15 or 20 years, might result in a more robust and accurate longer term forecast. Consumers' Coalition also notes that it is possible that a non-linear deferral methodology could result in a more robust and accurate longer term forecast. Consumers' Coalition also lacks access to the confidential and proprietary input forecasts relied upon by Manitoba Hydro as is as such unable to duplicate Manitoba Hydro's calculations.

QUESTION:

Please advise if Manitoba has considered the MPI "lower interest rate growth forecast" methodology or similar methodologies, and if so, please supply any analysis that considers its or their merits or deficiencies, and if not, why not?

RATIONALE FOR QUESTION:

Seeks to provide a more reliable estimate of short and medium term debt cost forecast, which is a major driver or rates.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.2 Tab 5 Figure 5.8	**Page No.:**	Page A-1 and Fall Update Pages 1-4 & attachment Page 22 of 51
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition notes that in fiscal 2017/18, and other years a significant portion of interest is capitalized or allocated to construction, and as such the finance expense does not fully describe the cash burden of interest paid or accruing in each year.

As indicated in earlier questions, Consumers' Coalition believes, that for forecasts longer than 3 or more years, Manitoba Hydro's choice of inputs and longer term methodology lead to forecast rates which substantially overstate the actual market interest rates they are purporting to estimate. The table below provides the average forecast, the average error, and the ratio of the average error to the average forecast, estimated by Consumers' Coalition for the 10 Year +, and the 90 day T-bill rates and forecasts developed as part of an earlier question.

Error 10 Year +	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
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While adopting a methodology similar to the MPI "lower interest rate growth forecast" might reduce the significant error seen in the second through fifth years of the forecast period, this methodology might not address the problem of the errors of massive proportion in the later years of the forecast.

Consumers' Coalition notes that it has not had the resources to test whether the MPI "lower interest rate growth forecast" assumption of a ten year period rather than five results in the <u>most</u> robust and accurate longer term forecast. Based on the significant error factors generated in years 8 and 9 of this analysis, it is probable that a linear deferral for a different

period, for example 15 or 20 years, might result in a more robust and accurate longer term forecast. Consumers' Coalition also notes that it is possible that a non-linear deferral methodology could result in a more robust and accurate longer term forecast. Consumers' Coalition also lacks access to the confidential and proprietary input forecasts relied upon by Manitoba Hydro as is as such unable to duplicate Manitoba Hydro's calculations.

QUESTION:

To test an MPI style methodology for a 10 year period, please prepare an interest rate forecast for T-bills and 10 year + forecast rates, adopting for the first 5 quarterly periods the Fall update data inputs and methodology and, for the 44th quarterly period use the ultimate values for T-bills of 3.90% and for 10 year + forecast rates of 4.45%. For values for the 6th quarterly period to the 43rd quarterly period, please use linear interpolation based on the 5th and 44th quarter values.

i. On a quarterly basis please provide the difference between the results provided by the standard Manitoba Hydro method and this method.
ii. Please use the interest rate forecast developed in (c) above as the basis for a sensitivity for the tables presented in Appendix 3.4.
iii. Please update the tables in Appendix 3.6 for the "-1% interest rate" scenario using the interest rate forecast developed in (c) above as the base level for that scenario.
iv. Please provide an updated Figure 5.8 and the numerical values supporting the 3 series presented therein, based upon the interest rate forecast developed in (c) above.

RATIONALE FOR QUESTION:

Seeks to provide a more reliable estimate of short and medium term debt cost forecast, which is a major driver or rates.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Appendix 3.1 Appendix 3.2 Tab 5 Figure 5.8	**Page No.:**	Page A-1 and Fall Update Pages 1-4 & attachment Page 22 of 51
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition notes that in fiscal 2017/18, and other years a significant portion of interest is capitalized or allocated to construction, and as such the finance expense does not fully describe the cash burden of interest paid or accruing in each year.

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90 Day T-bill	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year
Avg Error	0.24%	1.18%	2.84%	3.27%	3.35%	3.41%	3.42 %	3.46%	3.61%
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Error/AvgFcst	13%	45%	75%	81%	79%	79%	78%	79%	80%

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Consumers' Coalition believes that the proposed MPI "lower interest rate growth forecast" might, by reducing the speed at which forecast interest rates were increased up to the 10th year, substantially lessen the forecasting error for both short term and long term rates that seems systemic in the Manitoba Hydro forecast methodology for longer periods.

While adopting a methodology similar to the MPI "lower interest rate growth forecast" might reduce the significant error seen in the second through fifth years of the forecast period, this methodology might not address the problem of the errors of massive proportion in the later years of the forecast.

Consumers' Coalition notes that it has not had the resources to test whether the MPI "lower interest rate growth forecast" assumption of a ten year period rather than five results in the most robust and accurate longer term forecast. Based on the significant error factors generated in years 8 and 9 of this analysis, it is probable that a linear deferral for a different

period, for example 15 or 20 years, might result in a more robust and accurate longer term forecast. Consumers' Coalition also notes that it is possible that a non-linear deferral methodology could result in a more robust and accurate longer term forecast. Consumers' Coalition also lacks access to the confidential and proprietary input forecasts relied upon by Manitoba Hydro as is as such unable to duplicate Manitoba Hydro's calculations.

QUESTION:

To test an MPI style methodology for a 20 year period, please prepare an interest rate forecast for T-bills and 10 year + forecast rates, adopting for the first 5 quarterly periods the Fall update data inputs and methodology and, for the 84th quarterly period use the ultimate values for T-bills of 3.90% and for 10 year + forecast rates of 4.45%. For values for the 6th quarterly period to the 83rd quarterly period, please use linear interpolation based on the 5th and 84th quarter values.

i. On a quarterly basis please provide the difference between the results provided by the standard Manitoba Hydro method and this method.
ii. Please use the interest rate forecast developed in (d) above as the basis for a sensitivity for the tables presented in Appendix 3.4.
iii. Please update the tables in Appendix 3.6 for the "-1% interest rate" scenario using the interest rate forecast developed in (d) above as the base level for that scenario.
iv. Please provide an updated Figure 5.8 and the numerical values supporting the 3 series presented therein, based upon the interest rate forecast developed in (d) above.

RATIONALE FOR QUESTION:

Seeks to provide a more reliable estimate of short and medium term debt cost forecast, which is a major driver or rates.

RESPONSE:

RATIONALE FOR REFUSAL TO ANSWER THE QUESTION:

The Coalition withdrew this Information Request in its letter dated March 9, 2015.

Section:	Tab 5	Page No.:	Page 23 of 51
Topic:	Financing expense		
Subtopic:	Accuracy of 2 to 10 year interest rate forecasts for 10 Year +, and 90 day T-bill interest rates		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Consumers' Coalition observes in Figure 5.9, Tab 5, page 23 of 51, that declining weighted average interest rates are forecast for only 3 fiscal years, 2014/15, 2015/16 and 2016/17, not the 20 years of the forecast nor even the "first 10 years of the financial forecast".

Consumers' Coalition also recalls that in a previous hearing, Manitoba Hydro indicated that it would include in its financial forecasts approximately 20% of new debt as floating rate debt.

QUESTION:

a) Please confirm that the interest rates in this application are based upon 20% of new debt being forecast as floating rate debt?

b) Please extend the chart to and including 2023/24.

RATIONALE FOR QUESTION:

Clarifies makeup of forecast and provides insight into medium and longer term.

RESPONSE:

Since IFF10 and including IFF14, 20% of all new forecasted long term debt issuance is modeled as floating rate debt. Please see the response to PUB/MH-I-10a for the chart of Manitoba Hydro's weighted average interest rate from 2006/07 through to 2033/34.

Section:	Tab 3 Appendix 3.4	Page No.:	Page 13 of 21 Pages 1 and 2 of 6
Topic:	Financing expense		
Subtopic:	Equity ratio		
Issue:	Are "the proposed 3.95% rate increases" really "the minimum that are required to ... manage the deterioration in the Corporation's financial strength during the period of extensive investments" " Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Figure 3.4 in Tab 3 at page 13 of 21, appears to indicate equity ratios of less than 10% in certain years commencing in approximately fiscal 2023. Manitoba Hydro reports "In Manitoba Hydro's judgment, the projected deterioration in the equity ratio in MH14 is at the minimum acceptable financial operating level."

The Consumers' Coalition recalls that DBRS observes that in its October 23, 2002 rating report for the Manitoba Hydro Electric Board, DBRS calculated 93.8% debt in the 1996 capital structure, and 92.4% for 1997. The Consumers' Coalition also observes that prevailing interest rates were higher in those years than they are currently. DBRS observed the "Average coupon on long-term debt" was 9.22% for 1996 and 8.74% for 1997. The DBRS October 23, 2002 rating report shows that from 1995 through to 2002, in spite of the thinner equity layers and higher coupon rates prevailing the MHEB was rated "A", relying on the Province's long-term rating.

QUESTION:

Please provide the MH14 numerical values, to two decimal place accuracy, expressed in percentage terms, presented in Figure 3.4, that are less than 10.00% and indicate the years to which the values apply.

RATIONALE FOR QUESTION:

Goes to credibility of Hydro claim regarding financial target risk.

RESPONSE:

Please see the following table.

Equity Ratio

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MH14	22.41%	18.11%	16.32%	15.21%	14.14%	13.27%	12.22%	10.54%	9.93%	9.61%

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	9.57%	9.63%	10.11%	10.89%	12.10%	13.87%	16.17%	18.84%	21.80%	25.09%

Section:	Tab 3 Appendix 3.4	**Page No.:**	Page 13 of 21 Pages 1 and 2 of 6
Topic:	Financing expense		
Subtopic:	Equity ratio		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

Figure 3.4 in Tab 3 at page 13 of 21, appears to indicate equity ratios of less than 10% in certain years commencing in approximately fiscal 2023. Manitoba Hydro reports “In Manitoba Hydro’s judgment, the projected deterioration in the equity ratio in MH14 is at the minimum acceptable financial operating level.”

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QUESTION:

Please confirm that a 10% equity ratio is “acceptable”, and if not, why not?

RATIONALE FOR QUESTION:

Goes to credibility of Hydro claim regarding financial target risk.

RESPONSE:

As noted in the preamble to this question, the projected deterioration of the equity ratio in MH14 to the 10% level is in Manitoba Hydro's judgment is the minimum acceptable level. However, Manitoba Hydro is concerned that this level of deterioration of its financial reserves will limit its ability to absorb negative financial impacts such as a significant drought without the requirement to increase customer rates significantly higher than 3.95% per year.

Section:	Tab 3 Appendix 3.4	**Page No.:**	Page 13 of 21 Pages 1 and 2 of 6
Topic:	Financing expense		
Subtopic:	Equity ratio		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

PREAMBLE TO IR (IF ANY):

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QUESTION:

Please confirm that the equity ratio was in the range of 13% in fiscal 2014 and 14% in fiscal 2005.

RATIONALE FOR QUESTION:

Goes to credibility of Hydro claim regarding financial target risk.

RESPONSE:

Manitoba Hydro's equity ratio was 13% in 2003/04 and 15% in 2004/05.

It is important to note that Manitoba Hydro experienced a low net income in 2002/03 and a significant net loss in 2003/04 as a result of drought conditions. The impact of the drought on the financial results reduced the equity ratio from 23% in 2001/02 to 13% in 2003/04.

Section:	Tab 3 Appendix 3.4	**Page No.:**	Page 13 of 21 Pages 1 and 2 of 6
Topic:	Financing expense		
Subtopic:	Equity ratio		
Issue:	Are “the proposed 3.95% rate increases” really “the minimum that are required to ... manage the deterioration in the Corporation’s financial strength during the period of extensive investments” ” Tab 3, page 1 line 35		

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Figure 3.4 in Tab 3 at page 13 of 21, appears to indicate equity ratios of less than 10% in certain years commencing in approximately fiscal 2023. Manitoba Hydro reports “In Manitoba Hydro’s judgment, the projected deterioration in the equity ratio in MH14 is at the minimum acceptable financial operating level.”

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QUESTION:

Please provide the DBRS October 23, 2002 rating report for the Manitoba Hydro Electric Board,

RATIONALE FOR QUESTION:

Goes to credibility of Hydro claim regarding financial target risk.

RESPONSE:

Please see attached the DBRS credit rating report dated October 23, 2002 which has been highlighted to illustrate the following notable observations or quotes:

Regarding earnings and the importance of cash flow, in 2002 DBRS stated that:

> "As a regulated utility, Manitoba Hydro generates relatively stable earnings and cash-flow year-over-year. Earnings and cash flows have, however, improved substantially over the past two years. … Manitoba Hydro continues to generate sufficient operating cash flows to internally fund capital expenditures." [page 1]

Today, Manitoba Hydro is entering a period of extensive capital investment. Earnings and cash flow are projected to decrease, and the Corporation's negative free cash flows will require unprecedented levels of debt financing.

Regarding the debt to equity ratio, in 2002 DBRS stated that:

> "While leverage has improved in each of the last ten years, it remains high, at 78.9%, compared to investor owned utilities (typically in the 50% to 60% range) and is one of the highest of government-owned utilities." [page 4]

During the period from 1992 to 2014, the general historical trajectory of the equity ratio has been upward; however, moving forward, even with proposed 3.95% rate increases, Manitoba Hydro's financial ratios are projected to significantly deteriorate during the forecast period.

Manitoba Hydro receives a flow through credit rating from the Province of Manitoba. Since 1992, the general historical trajectory for the Province of Manitoba credit ratings has been upward and/or stable, and Manitoba Hydro has maintained its self-supporting status. As described in Tab 2 Section 2.4.4, the Province of Manitoba has a high credit rating which benefits Manitoba Hydro's customers by reducing the cost of borrowing that the Corporation must recover in its rates.

On August 18, 2014 Moody's placed the Province of Manitoba on a negative outlook. Moving forward, it is in the public interest for Manitoba Hydro to maintain its financial strength and not negatively the impact the Province's credit rating, borrowing costs or access to financing.

The Manitoba Hydro-Electric Board

The rating is based on the provincial guarantee. This report specifically analyzes Manitoba Hydro.

Report Date: October 23, 2002
Press Released: October 23, 2002
Previous Report: October 24, 2001

Matthew Kolodzie, P.Eng./Geneviève Lavallée, CFA
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Rating

Rating	Trend	Rating Action	Debt Rated
"A"	Positive	Confirmed	Long Term Debt
R-1 (low)	Stable	Confirmed	Commercial Paper/T-Bills

Rating History

	Current	2001	2000	1999	1998	1997	1996	1995
Long Term Debt	"A"	"A"	"A"	"A"	"A"	"A"	"A"	"A"
Commercial Paper/T-Bills	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Rating Update

The ratings for The Manitoba Hydro-Electric Board ("Manitoba Hydro" or the "Utility") are a flow-through of the ratings of the Province of Manitoba (the "Province"), as the Utility's debt securities are direct obligations of the Province or are guaranteed by the Province. DBRS placed the Province's long-term rating on a Positive trend on June 21, 2002.

As a regulated utility, Manitoba Hydro generates relatively stable earnings and cash flow year-over-year. Earnings and cash flows have, however, improved substantially over the past two years. This improvement is largely due to the increase in exports sales to the U.S., which has been facilitated by the Utility's coordination agreement with the Midwest Independent System Operator ("MISO"), giving Manitoba Hydro greater access to customers in U.S. markets. Manitoba Hydro benefits from its low-cost hydro-based generation capacity, which provides the Utility with electricity that is extremely competitive in other jurisdictions. Earnings and cash flow volatility have increased largely as a result of its greater participation in the export markets and electricity price fluctuations in the U.S. Manitoba Hydro has recently signed a ten-year power supply contract with NSP Minnesota (a subsidiary of Xcel Energy Inc.), which will replace its existing contract that expires in 2005. This contract will provide for a degree of earnings and cash flow stability for a significant portion of Manitoba Hydro's energy exports.

Synergies gained through the integration of Centra Gas have provided a stable source of accretive earnings. Similar results are expected from the acquisition of Winnipeg Hydro, which closed September 2002.

While Manitoba Hydro continues to generate sufficient operating cash flows to internally fund capital expenditures, distributions payable to the Province of $288 million over the next two years will constrain the Utility's ability to reduce debt. As such, leverage and key financial ratios will remain weak in comparison to investor-owned utilities.

Other factors that will negatively impact cash flow over the mid- to long-term include: (1) a doubling of water rental fees, implemented April 2001; (2) the equalization of northern and rural customer rates to levels charged in Winnipeg; and (3) no rate increases on the horizon to offset the difference.

Rating Considerations

Strengths:

- Debt is guaranteed by the provincial government
- Low-cost hydro-based generation with storage capacity
- Interconnections with U.S., Saskatchewan, and Ontario
- Centra Gas and Winnipeg Hydro acquisitions are expected to improve profitability
- Cash flows sufficient to internally fund capital expenditures

Challenges:

- High debt level weakens most financial ratios
- Earnings are sensitive to hydrologic conditions
- Earnings somewhat sensitive to exchange rates
- Domestic energy rates have not increased since 1997
- One NFA First Nation claim has not been settled

Financial Information

	12 months ended	For years ended March 31					
	June, 30 2002	2002	2001	2000	1999	1998	1997
EBIT interest coverage (times)	1.31	1.39	1.53	1.31	1.19	1.22	1.21
Net debt in capital structure (1)	83.0%	82.9%	85.3%	88.1%	89.5%	90.8%	92.4%
Cash flow/total debt (times)	0.07	0.07	0.08	0.06	0.06	0.06	0.06
Cash flow/capital expenditures (times)	0.94	1.08	1.43	1.15	0.98	1.35	1.03
Net income ($ millions)	176	214	270	152	100	111	101
Operating cash flow ($ millions)	440	474	519	379	325	334	307
Electricity sales (millions of kWh)	-	29,214	28,806	26,688	27,692	29,462	27,567
Electricity revenues (cents per kWh sold)	-	4.70	4.38	4.17	3.88	3.52	3.69
Variable costs (cents per net gen kWh sold)	-	1.13	1.10	1.11	0.94	0.75	0.84
Fixed costs (cents per net gen kWh sold)	-	3.27	2.79	2.93	2.69	2.41	2.50
Average coupon on long-term debt	-	8.17%	8.31%	8.38%	8.56%	8.79%	8.74%

(1) Net of sinking fund assets. Customer contributions excluded from capital structure.

The Company

The Manitoba Hydro-Electric Board, a wholly owned Crown corporation of the Province of Manitoba, generates, transmits, and distributes electricity in the Province of Manitoba. With the acquisition of the Province's private sector gas distributor, Centra Gas Manitoba in July 1999, Manitoba hydro is now the largest gas distributor in Manitoba.

Authorized Paper Amount Limited to US$500 million (includes T-Bills).

REGULATION

The Manitoba Public Utilities Board ("PUB") regulates electricity rates. Proposed rate changes are submitted to the PUB by Manitoba Hydro. Traditionally, rates are reviewed annually and changes, if any, are effective the first of April. Domestic rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not be increased in F2003. In November 2001, the provincial government legislated equal northern, rural, and urban electricity rates throughout the Province.

Prices for electricity exported or imported are determined by negotiated contracts. Export permits must be approved by the National Energy Board ("NEB").

In 1997, the Manitoba Legislature enacted significant amendments to the Manitoba Hydro Act. While Manitoba Hydro and Winnipeg Hydro remain the sole retail electricity suppliers in Manitoba, other utilities may access the transmission system to reach other customers in neighbouring provinces and states. The amended Act explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures, and to create subsidiaries. Manitoba Hydro has restructured its operations into one Corporate unit and three operating units: Power Supply, Transmission and Distribution, and Customer Service and Marketing. The structure mirrors those of other utilities who are adhering to Federal Energy Regulatory Commission ("FERC") directives in the U.S.

There are presently no plans to move to full retail competition in the Province, as it is believed that Manitoba prices would likely increase from current levels. Manitoba retail customers currently enjoy rates that are among the lowest in North America because of Manitoba Hydro's predominantly hydroelectric generation, profitable exports, and efficient resource management. Based on forecasts of the wholesale trading price in the MISO region, Manitoba customers would pay 30% more if domestic electricity rates were market based.

RATING CONSIDERATIONS

Strengths: (1) Manitoba Hydro's debt securities are direct obligations of, or are guaranteed by, the provincial government. As such, the rating assigned to Manitoba Hydro is a flow-through of the rating of the Province of Manitoba.

(2) Low-cost hydro-based generating capacity accounts for approximately 95% of installed capacity (as at March 31, 2002) and results in one of the lowest variable cost structures in Canada (about 1.3¢ per kWh), surpassed only by Churchill Falls in Labrador. Given the water storage capacity of its hydro-based generating facilities, Manitoba Hydro is in an excellent position to trade power, buying low-cost power during off-peak hours, and selling its own generated power during peak periods at higher rates. Geographically diverse drainage basins reduce fluctuations in water flows and water levels caused by weather patterns in a specific region.

(3) Manitoba Hydro has excellent interconnections (about 55% of installed capacity) with 2,050 MW to MISO, 450 MW to Saskatchewan and 263 MW to Ontario. This provides additional markets to sell power. Prior to open access in 1996, all exported power was sold at the border only to directly interconnected neighbouring utilities, which in turn delivered the power to their customers or re-sold it at a profit to other utilities. Due to open access and the coordination agreement with MISO, Manitoba Hydro has positioned itself to be able to sell to more distant companies.

(4) The acquisition of Centra Gas Manitoba will continue to generate material synergies over the longer term, expected to generate approximately $12 million in annual cost savings. The acquisition of Winnipeg Hydro, which closed in September 2002, will provide opportunities to improve profitability through systems integration and efficiency improvements.

Challenges: (1) Debt levels remain high, resulting in weak financial ratios.

(2) Given that approximately 95% of Manitoba Hydro's installed generating capacity is hydro-based, earnings and cash flows are sensitive to hydrologic conditions. The Utility's diverse drainage basins offer some protection to mitigate this problem as hydrological conditions vary across drainage basins. Also, the addition of two new natural gas-fired turbines at the Brandon Generating Station (260 MW) in F2003 will assist in meeting demand during periods of poor hydrological conditions.

(3) The income statement and balance sheet are sensitive to changes in the U.S. dollar/Canadian dollar exchange rate since approximately 60% (at March 31, 2002) of the Utility's outstanding debt is denominated in U.S. dollars. While US$ debt servicing costs are fully hedged by export revenues, any surplus US$ export revenues are sensitive to changes in the exchange rate, thus increasing earnings volatility.

(4) Domestic electricity rates for large industrial customers have been voluntarily frozen since 1992 and since 1997 for residential customers, and will not likely be increased in the foreseeable future. Electricity rates in Manitoba are among the lowest in North America, and contribute to weaker profitability. However, low rates may benefit Manitoba Hydro by creating a barrier to entry for competitors.

(5) One Northern Flood Agreement ("NFA") First Nation claim has not been settled. Manitoba Hydro continues to address the adverse effects of its northern hydroelectric developments on five First Nation communities. Under the Northern Flood Agreement with the provincial government, the Utility assumed certain obligations of the Province associated with these northern development projects. Four out of five native claims have reached a settlement.

EARNINGS AND OUTLOOK

($ millions)	12 months ended June, 30 2002	For years ended March 31 2002	2001	2000	1999	1998	1997
Net electricity revenues	1,280	1,313	1,231	1,095	1,036	1,030	1,012
Net gas revenues	117	114	120	87	-	-	-
Total net revenues	1,408	1,438	1,359	1,193	1,043	1,036	1,017
EBITDA	943	975	996	838	764	774	749
EBIT	679	715	747	611	566	583	572
Net interest expense	519	515	489	468	475	477	472
Net income	176	214	270	152	100	111	101

Net electricity revenues are gross revenues less cost of purchased power. Net gas revenues are gross revenues less cost of gas.

Earnings:

- Key factors contributing to the 4.3% drop in EBIT in F2002 are:
  - The doubling of water rental fees to $113 million
  - A larger volume of higher-cost electricity imports to meet increased energy demands, mainly from general service customers
  - Milder temperatures, which resulted in lower electricity sales and natural gas deliveries to residential customers
- The above factors more than offset the following positive impacts on EBIT:
  - A 23% increase in export revenues, despite lower export volumes, resulting from higher prices on the export market
  - Higher demand from industrial and general service customers as the size of this customer base grew
  - A decrease in the cost of fuel, due to a smaller amount of coal consumed for thermal generation
- Hydrologic conditions remained favourable in F2002, as Manitoba Hydro was able to produce roughly the same level of low-cost hydro-generation over F2001
- While electricity export volumes (in kWh) have remained relatively stable over that last several years, the price received per kWh has improved significantly (5.63¢ per kWh in F2002 versus 2.83¢ per kWh in F1999)

Outlook:

- Near-term earnings are expected to remain strong, supported by favourable hydrologic conditions and stable export sales volumes
- However, current lower export market prices will reduce the margins on exports in F2003
- The acquisition of Winnipeg Hydro is expected to be accretive to Manitoba Hydro's earnings as efficiencies are gained the integration of billing systems and system support
- The implementation of uniform rates for all customers across the province will reduce earnings by approximately $14 million annually
- Earnings should continue to benefit from the electricity market restructuring and the Utility's coordination agreement with MISO, which has allowed for growth of electricity exports
- Steady load growth, from an expanding customer base, will continue to benefit the Utility over the longer term
- Manitoba Hydro's low-cost hydro-based generation is a competitive advantage over many U.S. utilities
- However, exporting power to the U.S. exposes the Utility somewhat to exchange rate fluctuations, which will contribute to earnings volatility over the medium to long term

FINANCIAL PROFILE AND SENSITIVITY ANALYSIS

Cash Flow Statement ($ millions)	12 months ended June 2002	Years ended March 31 2002	2001	2000	1999	**Stress Testing** (1) Year 1	Year 2	Year 3
Net income	176.0	214.0	270.0	152.0	100.1	175.4	156.8	137.5
Depreciation and amortization	264.0	260.0	249.0	227.0	198.0	274.0	281.1	287.8
Other non-cash adjustments	-	-	-	-	27.1	-	-	-
Cash Flow From Operations	440.0	474.0	519.0	379.0	325.2	449.4	437.9	425.4
Capital expenditures	(468.0)	(439.0)	(362.0)	(330.0)	(331.6)	(400.0)	(400.0)	(400.0)
Dividends paid	-	-	-	-	-	(144.0)	(144.0)	-
Cash Flow Before Working Capital	(28.0)	35.0	157.0	49.0	(6.4)	(94.6)	(106.1)	25.4
Change in working capital	105.0	80.0	(185.0)	(5.0)	40.6	-	-	-
Net Free Cash Surplus/(Deficit)	77.0	115.0	(28.0)	44.0	34.2	(94.6)	(106.1)	25.4
Other investing, acquisition/divest. (2)	(58.0)	(72.0)	(40.0)	(348.0)	(44.8)	(50.0)	(50.0)	(50.0)
Net financing	33.0	(27.0)	51.0	262.0	(65.5)	144.6	156.1	24.6
Change in Net Cash	52.0	16.0	(17.0)	(42.0)	(76.1)	0.0	0.0	0.0
Key Figures and Ratios								
Total debt	6,378	6,326	6,306	6,070	5,682	6,471	6,627	6,651
% debt in capital structure	83.0%	82.9%	85.3%	88.1%	89.5%	82.9%	83.1%	81.8%
EBITDA interest coverage (times)	1.82	1.89	2.04	1.79	1.61	1.89	1.85	1.80
EBIT interest coverage (times)	1.31	1.39	1.53	1.31	1.19	1.35	1.30	1.26
Cash flow/ total debt	0.07	0.07	0.08	0.06	0.06	0.07	0.07	0.06

(1) Stress testing is for years ending March 31. (2) Other investing includes Centra Gas acquisition in F2000.

Financial Profile:

- Weaker earnings contributed to the decrease in cash flow from operations in F2002, which was down 8.7% from the historical high in F2001
- Despite the decrease, cash flow from operations remained sufficient to internally fund capital expenditures
- Along with general system upgrades, key capital expenditures in F2002 were:
  - A new natural gas-fired combustion turbine being installed at Brandon ($87 million)
  - The Selkirk Generating Station fuel conversion project ($19 million)
  - Transmission upgrades to increase export capacity ($41 million)
- While leverage has improved in each of the last ten years, it remains high, at 78.9%, compared to investor-owned utilities (typically in the 50% to 60% range) and is one of the highest of government-owned utilities
- As a result of high leverage, interest coverage and cash flow to debt remains relatively weak for a regulated utility
- Since it is a Crown corporation, Manitoba Hydro faces certain restrictions that investor-owned utilities do not face, such as a lack of access to equity markets
- Debt level sensitivity to U.S. dollar exchange rates is material as approximately 60% (as at March 31, 2002) of the Utility's debt portfolio is U.S. dollar denominated debt

Outlook*:*

- New legislation requires Manitoba Hydro to pay distributions of up to 75% of net income to the Province in F2003 and F2004, but is not to exceed $288 million in total over the two years
- The distribution payments to the Province will constrain the Utility's ability to internally fund capital expenditures with operating cash flow, and will limit the Utility's ability to pay down debt an achieve its leverage target of 75% of capitalization
- High leverage will continue to result in weaker key financial ratios compared to investor-owned utilities
- The Utility is currently evaluating several new hydroelectric projects in northern Manitoba that may commence over the next ten years
  - Any new project would be primarily debt-financed, which would likely weaken the balance sheet

Sensitivity Analysis:

- DBRS stress tests the financial strength of companies analyzed to measure their sensitivity under various adverse scenarios
- The assumptions used in are not based on any specific information provided by the Utility or DBRS expectations concerning future performance
- The following three-year scenario has been assumed:
  - EBITDA falls by 2% in Year 1, and remains constant thereafter
  - Maintenance capex of $400 million annually.
  - Distributions to the Province of $144 million in each of Years 1 and 2, and no distributions in Year 3
  - Other investments of $50 million annually
  - Any free cash flow deficits are entirely debt financed
- Under this scenario:
  - Manitoba Hydro would require over $300 million in external financing to fund the cash flow deficit
  - The majority of the cash flow deficit is attributable to the cash distributions to the Province in F2002 and F2003, which limits near-term improvement to the balance sheet
  - However, the provincial guarantee still carries the rating

LONG-TERM DEBT MATURITIES AND BANK LINES

A credit facility of $500 million available either in Canadian or U.S. currency.

	F2003	F2004	F2005	F2006	F2007
($ millions)	524	319	211	-	323

THE WATERSHEDS AND STORAGE CAPACITY

Manitoba Hydro draws water from four distinct watersheds. (1) The main water source is the Winnipeg River, which runs through northern Minnesota and northwestern Ontario. Because of the 900 feet of head from the source, the large volume of water, and the fact that the same water goes through virtually all the generators which are all downstream, this watershed typically accounts for about 40% of the electricity produced by Manitoba Hydro.

(2) The Prairie region, which extends to the Continental Divide, is drained by the Saskatchewan River. This watershed accounts for about one-quarter of the energy produced. The watershed is large but relatively dry, and most parts of the southern prairies contribute no water runoff.

(3) The Churchill River watershed, which includes northern Saskatchewan and northwestern Manitoba, contributes approximately 22% of energy generated.

(4) The Red River watershed, which includes northern Minnesota, typically contributes about 4% to 15% of energy, with most of the water coming in the month of May. The remaining water comes from other areas in the Province. This four-watershed base provides some diversification and stability to available water levels used to produce electricity.

Water levels are amplified by three other characteristics: (1) The cold temperatures reduce evaporation rates and much of the water is frozen for up to five months a year. (2) The fact that much of the soil is rock reduces seepage and increases runoff. (3) Lake Winnipeg, Cedar Lake, and South Indian Lake serve as large storage reservoirs. This gives the Utility the flexibility to produce electricity when it wishes (i.e., when prices are higher). Electric industry restructuring and deregulation is well under way in many parts of the U.S., and competitive pressures will favour those utilities with the lowest cost structures. With access to wholesale markets in the U.S. through MISO, Manitoba Hydro is in a good position to sell electricity to more users in the U.S. at higher prices. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices, and selling its electricity during peak demand periods at higher prices). This will grow in the future and have the effect of ultimately raising the average unit price received for electricity sold by Manitoba Hydro.

Manitoba also has the advantage of having about 5,000 more megawatts of future generating capacity, which can be developed, virtually equal to the 5,000 megawatts of capacity presently in place. With changes to the Hydro Act, it now has the legal flexibility to form joint ventures and use third-party sources to develop the power. Environmental issues are believed to be manageable, and agreements with native bands regarding new projects appear to be feasible. In addition, most infrastructure is already in place. Interest costs are also at record lows, which makes financing the projects more economic. However, transmission losses due to remoteness of facilities and distances between facilities and markets are significant, and there is a limited market for the power domestically (there are few energy intensive industries in the Province).

PROVINCE OF MANITOBA

DBRS confirmed the long-term and short-term ratings of the Province of Manitoba (the “Province”) at “A” and R-1 (low), respectively on June 21, 2002. The trend on the short-term rating remains Stable whereas that on the long-term rating was changed from Stable to Positive. The trend change primarily reflects: (1) improved, though still volatile fiscal results posted by the Province in recent years; (2) the stronger and more diversified base of the provincial economy; and (3) a much lower debt to GDP ratio, which has been declining consistently over the last seven years, from 47.8% in 1995 to 35.9% at March 31, 2002.

The Province remained in a sound fiscal position in 2001-02, with a DBRS-adjusted surplus of $16 million, only $1 million below target. Strong earnings from Manitoba Hydro and a strong increase in equalization transfers more than offset a sharp decline in tax revenues, allowing the fiscal balance to remain in a surplus position. Total DBRS-adjusted debt (tax-supported debt plus unfunded pension liabilities) was little changed during the year, but declined in importance as a percentage of GDP to 35.9%, from 37.2% the year before.

Fiscal results are projected to weaken markedly in 2002-03, as lower Manitoba Hydro earnings, sluggish tax collection and broad-based, though moderate expenditure increases are expected to lead to a DBRS-adjusted deficit of $144 million (including increases in unfunded pension liabilities). Total DBRS-adjusted debt is also expected to grow to $12.8 billion in 2002-03. A marked increase in the debt of tax-supported Crown corporations, continued growth in unfunded pension liabilities, and sustained investments in education and health infrastructure are expected to account for most of the debt increase. As a result, the Province’s debt to GDP ratio should change little in 2002-03 despite accelerating economic activity. Although unfounded pension liabilities and capital expenditures are expected to continue to put pressure on debt over the medium term, the Province’s long-term debt outlook remains positive, supported by prudent fiscal management and a comprehensive plan to retire both general purpose debt and unfounded pension liabilities by 2036.

Key challenges the Province faces include: (1) a high dependence on federal transfers, which continue to account for 30% to 34% of total provincial revenue; (2) rapidly increasing health costs (40% of total expenditures in 2002-03) driven by inter-provincial wage competition, rising demand for services, and escalating prices for drugs and technology; and (3) relatively large unfunded pension liabilities, at $3 billion, or 8.7% of provincial GDP.

The Manitoba Hydro-Electric Board

Balance Sheet ($ millions)	As at June 30	As at March 31			As at June 30	As at March 31	
Assets	2002	2002	2001	**Liabilities & Equity**	2002	2002	2001
Cash + equivalents	173	14	0	Short-term debt	130	180	192
Accounts receivable	366	386	476	Long-term debt due 1yr.	251	524	496
Accrued + prepaid	124	109	75	A/P & accrued	292	309	301
Current assets	663	509	551	Current liabilities	673	1,013	989
Net fixed assets	6,671	6,626	6,428	Long-term debt	7,321	7,137	6,968
Deferred debt costs & assets	1,121	1,282	1,194	Def'd + other liab.	231	230	254
Pension assets	482	473	443	Pension obligation	429	422	386
Sinking funds	1,324	1,515	1,350	Equity	1,607	1,603	1,369
Total	10,261	10,405	9,966	Total	10,261	10,405	9,966

Ratio Analysis	12 months ended	For years ended March 31						
Liquidity Ratios	June 30, 2002	2002	2001	2000	1999	1998	1997	1996
Current ratio	0.99	0.50	0.56	0.81	0.67	0.65	0.26	0.38
Accumulated depreciation/gross fixed assets	-	30.0%	28.9%	27.7%	27.7%	26.8%	25.8%	25.1%
Cash flow/total debt (1)	0.07	0.07	0.08	0.06	0.06	0.06	0.06	0.05
Cash flow/capital expenditures (2)	0.94	1.08	1.43	1.15	0.98	1.35	1.03	1.00
% debt in the capital structure (1)	83.0%	82.9%	85.3%	88.1%	89.5%	90.8%	92.4%	93.8%
Average coupon on long-term debt	-	8.17%	8.31%	8.38%	8.56%	8.79%	8.74%	9.22%
Coverage Ratios (3)								
EBIT interest coverage	1.31	1.39	1.53	1.31	1.19	1.22	1.21	1.15
EBITDA interest coverage	1.82	1.89	2.04	1.79	1.61	1.62	1.59	1.52
Fixed-charges coverage	1.31	1.39	1.53	1.31	1.19	1.22	1.21	1.15
Earnings Quality / Operating Efficiency								
Power purchases/revenues	4.9%	4.1%	2.2%	1.5%	3.5%	0.5%	0.6%	0.7%
Fuel costs/revenues	0.7%	0.7%	1.3%	1.2%	1.9%	0.8%	0.7%	0.7%
Operating margin	40.1%	41.6%	46.0%	43.4%	44.5%	48.2%	48.4%	47.9%
Net margin (before extras.)	11.9%	14.3%	19.4%	12.6%	9.3%	10.6%	9.9%	7.1%
Return on avg. equity (before extras.)	13.5%	17.9%	28.3%	20.5%	16.3%	21.6%	25.0%	22.0%
Profit returned to government	57.3%	52.9%	37.6%	50.5%	54.6%	52.5%	53.1%	60.7%
Customers/employee	-	85	86	86	97	99	100	98
Growth in customer base	-	0.6%	0.3%	0.8%	1.2%	0.7%	0.7%	0.6%
GWh sold/employee	-	6.1	6.1	5.7	6.7	7.4	7.0	6.4
Self Generation - Cost Structure (4)								
OM&A		1.09	1.04	1.05	0.86	0.72	0.81	0.88
Fuel		0.04	0.06	0.06	0.08	0.03	0.03	0.03
Variable costs		1.13	1.10	1.11	0.94	0.75	0.84	0.91
Government levies		0.86	0.58	0.60	0.46	0.42	0.42	0.43
Net interest expense		1.52	1.36	1.48	1.50	1.35	1.44	1.61
Total cash costs		3.51	3.04	3.19	2.90	2.52	2.70	2.95
Non-cash financial charges		(0.05)	(0.04)	(0.03)	(0.03)	(0.02)	(0.01)	(0.01)
Depreciation		0.93	0.89	0.88	0.76	0.65	0.65	0.67
Total costs		4.40	3.89	4.04	3.63	3.16	3.34	3.62
Purchased power (cents per gross kWh purchased)		6.30	3.60	1.79	1.97	3.21	3.43	1.72
Export revenues - U.S. (cents/kWh)		5.03	4.03	3.41	2.83	2.27	2.45	2.65
Export revenues - Inter-provincial (cents/kWh)		3.80	3.68	3.58	3.08	1.44	1.29	1.16

(1) Sinking fund assets netted from debt obligations. Includes FX translation adjustments for U.S. dollar debt and sinking fund assets, excludes customer contributions.
(2) Capital expenditures are net of customer contributions.
(3) Before capitalized interest, AFUDC, and debt amortizations.
(4) Internally generated energy less energy used + lost - excludes power purchases. Transmission losses apportioned relative to total energy supplied.

Operating Statistics For years ended March 31

Electricity Sold (millions kWh)		2002	2001	2000	1999	1998	1997	1996
Residential		5,206	5,282	4,928	4,947	4,937	5,340	5,288
Commercial/industrial		10,258	9,939	9,448	9,657	9,430	9,159	8,931
Winnipeg Hydro (net transfer)		1,452	1,431	1,401	1,684	1,528	1,569	1,582
Total Manitoba		16,916	16,652	15,777	16,288	15,895	16,068	15,801
Export sales - domestic (scheduled)		2,448	2,958	2,513	1,508	1,261	1,167	713
- U.S. (scheduled)		9,850	9,196	8,398	9,896	12,306	10,332	8,946
Total exports		12,298	12,154	10,911	11,404	13,567	11,499	9,659
Total electricity sales for billing purposes		29,214	28,806	26,688	27,692	29,462	27,567	25,460
Energy sales growth		1.4%	7.9%	(3.6%)	(6.0%)	6.9%	8.3%	5.4%
Generation Capacity								
Winnipeg Hydro		143	139	133	134	134	140	140
Hydro	92.6%	4,799	4,840	4,750	4,767	4,767	4,834	4,834
Gas	4.5%	233	233	233	236	236	237	369
Oil	0.2%	10	9	8	11	15	20	20
Total installed capacity (MW)		5,185	5,221	5,124	5,148	5,152	5,231	5,363
Energy Generated (millions kWh)								
Hydro	98.4%	31,046	30,697	28,360	28,303	32,806	30,711	28,129
Coal & oil	1.6%	491	870	684	949	301	198	228
Gross energy generated	97.0%	31,537	31,567	29,044	29,252	33,107	30,909	28,357
Plus: net power exchange		968	834	1,004	1,935	168	169	401
Energy generated & purchased		32,505	32,401	30,048	31,187	33,275	31,078	28,758
Less: transmission losses & internal use		3,818	3,666	3,360	3,495	3,813	3,511	3,298
Total system demand*		28,687	28,735	26,688	27,692	29,462	27,567	25,460

* Total system demand differs from total sales for billing purposes due to differences between the energy scheduled for sale and actual meter readings.

	2002	2001	2000	1999	1998	1997	1996
(Energy lost + used)/(energy gen. + purch.)	11.7%	11.3%	11.2%	11.2%	11.5%	11.3%	11.5%
Peak demand (MW)	3,760	3,637	3,524	3,559	3,490	3,409	3,588
Peak demand/installed capacity	72.5%	69.7%	68.8%	69.1%	67.7%	65.2%	66.9%
Export Interconnections							
Ontario Hydro	263	263	240	240	240	240	240
Saskatchewan Power	450	450	450	450	300	300	300
U.S. - MAPP	2,050	2,050	2,050	2,050	1,900	1,900	1,900
Total (MW)	2,763	2,763	2,740	2,740	2,440	2,440	2,440
Interconnections as a % of installed capacity	53.3%	52.9%	53.5%	53.2%	47.4%	46.6%	45.5%
Gas Deliveries (billions of cubic feet)							
Residential	22.8	25	18.7				
Commercial/industrial	31.7	34	25.6				
Transportation	17.7	18	12.9				
	72.2	76.7	57.2				