MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act*

**AND IN THE MATTER OF Manitoba Hydro's
2015/16 & 2016/17 General Rate Application**

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of Manitoba Industrial Power Users Group ("MIPUG");

PATRICIA LEE, BCRI INC. on behalf of Consumers' Association of Canada/Winnipeg Harvest ("COALITION") and MIPUG; and,

ROGER COLTON, FISHER SHEENAN & COLTON on behalf of Green Action Centre ("GAC");

May 20, 2015

Manitoba Hydro

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1.0 INTRODUCTION

Manitoba Hydro's Rebuttal Evidence addresses the written evidence filed on behalf of the following parties with respect to Manitoba Hydro's 2015/16 & 2016/17 General Rate Application:

- Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group ("MIPUG");
- Ms. Patricia Lee on behalf of the Consumers Association of Canada/Winnipeg Harvest ("COALITION") and MIPUG; and,
- Mr. Roger Colton on behalf of the Green Action Centre ("GAC").

2.0 MANITOBA HYDRO'S FINANCIAL TARGETS AND RESERVES

2.1 Manitoba Hydro's Current Financial Targets Remain as an Appropriate Guide for Rate-Setting Purposes

Mr. Bowman states on page 4 of his written testimony that "*The financial targets that Hydro uses to set net income and retained earnings requirements are currently being reviewed; therefore, for this proceeding they are not reviewed in detail nor used as a guide to set rates.*"

Manitoba Hydro is currently in the process of reviewing its financial targets. During this review, the current targets remain as the key measure of the Corporation's financial strength. Rate stability for customers is dependent on the financial strength of the Corporation.

While MH14 projects that Manitoba Hydro's financial ratios will deteriorate significantly below targets during the period of significant investment, it is important that Manitoba Hydro's financial position improves following the investment period. External stakeholders, such as credit rating agencies and lenders, will closely monitor Manitoba Hydro's progression towards its financial targets.

2.2 Adequate Financial Reserves are Essential to Ensure Rate Stability for Customers

Mr. Bowman states on pages C-9 and page C-10: "*The main rationale for targeting a particular capital structure or reserve level is to have ratepayers contribute, through today's rates, to protect themselves from future rate shocks, through appropriate reserves for rate stabilization.*"

Mr. Bowman calculates the drawdown of reserves associated with a 5-year drought in the range of $1.037 billion to $1.220 billion (revised page C-9, lines 4 and 9) and alludes that this range of reserves is an appropriate level necessary for customer rate stability.

Mr. Bowman's approach considers the absolute change in retained earnings from the start of the drought to the final year of the drought. Mr. Bowman's provides an estimated calculation of $59 million in net income based on net interchange revenue of $151 million for the flow year 1988 under 2017 assumptions less non-flow-related net costs of $92 million based on 2017 all other revenues and costs. Mr. Bowman then assumes that 2017 assumptions remain constant over a 5-year drought period and consequently the $92 million in non-flow-related costs are fixed over the five-year drought period, varying only the net interchange revenue under 2017 assumptions.

Manitoba Hydro's evidence on page 22 of IFF14, Appendix 3.3 calculates that the impact of a 5-year drought is $1.7 billion (including the impact of compounding interest) and is based on the change in retained earnings balances (with and without drought) at the end of the five years.

The following Figure shows the differences in the calculations.

Figure 1. Comparison of Manitoba Hydro and MIPUG (Bowman) Calculation of Drought

($Millions)						
Corresponding Drought Year	**1988**	**1989**	**1990**	**1991**	**1992**	**Total 1988-1992**
Fiscal Year Ending	**2017**	**2018**	**2019**	**2020**	**2021**	**2017-2021**
MH14:						
Net Flow-Related Revenue[1]	147	142	160	195	459	1,102
Non-Flow-Related Net Cost[2]	(87)	(78)	(249)	(311)	(637)	(1,362)
Net Income with No 5-Year Drought	59	64	(90)	(116)	(178)	(260)
MH 5-Year Drought Scenario:						
Net Flow-Related Revenue[1]	(176)	(317)	(49)	(57)	278	(321)
Non-Flow-Related Net Cost[2]	(102)	(147)	(300)	(378)	(722)	(1,650)
Net Income with 5-Year Drought	(279)	(464)	(349)	(435)	(444)	(1,971)
Change in Net Income MH 5-Year Drought Scenario Compared to MH14	**(338)**	**(528)**	**(260)**	**(320)**	**(265)**	**(1,711)**
MIPUG (P. Bowman) Evidence:						
Net Flow-Related Revenue[1]	(181)	(334)	(22)	(47)	7	(577)
Non-Flow-Related Net Cost[2]	(92)	(92)	(92)	(92)	(92)	(460)
Calculated Net Income	(273)	(426)	(114)	(139)	(85)	(1,037)

[1] Net Flow-Related Revenue = Extraprovincial Revenue - Water Rentals - Fuel and Power Purchased

[2] Non-Flow-Related Net Cost = Net Income - Net Flow-Related Revenue; OR

[2] Non-Flow-Related Net Cost = Domestic Revenue + Other Revenue - Total Expenses excluding Water Rentals and Fuel & Power Purchased + Non-Controlling Interest

Mr. Bowman's simplified calculation is flawed and does not reflect the following:

- The changes in finance and depreciation expense associated with capital investments over the same period in the non-flow-related net costs;
- The change in electricity firm or opportunity export prices;
- The increase in Manitoba load; or
- The compounding interest effects due to increasing borrowing requirements.

The financial effects of a drought are not the only significant risk faced by Manitoba Hydro. In addition to drought and infrastructure loss, the sensitivity analysis shown in Table 16-1 in IFF14 (Appendix 3.3, page 22) shows that the forecast is also extremely sensitive to changes in other key assumptions such as interest rates, export prices, capital expenditures and customer rate adjustments. Should more than one risk occur in tandem, the minimum retained earnings balance of $1 or $1.2 billion, as proposed by Mr. Bowman, is not sufficient to maintain a reasonable financial position or protect customers from rate volatility.

Given the annual variability in net income and cash flow due to rapidly changing water flow conditions, it is financially prudent to include a reasonable contribution to retained earnings in rates in 2016 and 2017 to mitigate the deterioration of Manitoba Hydro's financial position during a period of extensive capital investment and promote customer rate stability. If the future results in a more favourable financial position, the reasonable contribution to retained earnings serves to reduce future rate increases that would have otherwise been required.

It is Manitoba Hydro's assertion that, Mr. Bowman's simplified calculations significantly understate the impact of a 5-year drought, particularly if the drought is assumed to commence at the outset of Manitoba Hydro's capital investment program, and due to the limitations of Mr. Bowman's calculation, the drought sensitivity in Appendix 3.6, page 26 should be relied upon, in addition to the financial impacts of other risk factors, to base any judgments on the adequacy of financial reserves.

2.3 Adequate Financial Reserves are Essential to Maintaining a Self-Supporting Status for Credit Rating-Purposes

Mr. Bowman's states on page C-6 that, "*Many Crown utilities (both electrical and other) have operated for long periods with little to no "equity."*"

Manitoba Hydro notes that comparable Crown utilities, such as BC Hydro and Hydro Quebec, currently operate with equity ratios of 20% to 30% and some utilities are moving to strengthening their capital structure, such as BC Hydro which is planning to strengthen its debt/equity ratio to 60:40.

New Brunswick Power (NB Power) has operated with equity ratios lower than 10%. NB Power's high costs of generation asset refurbishments, decommissioning and volatile earnings due to hydrology and fuel and power purchase prices contributed to the utility's continued "excessively" high leverage. This was a consideration in the Province of New Brunswick's 2009 and 2012 credit rating downgrades. New Brunswick's revised Energy Act mandates the utility to substantially reduce its debt levels to achieve an equity ratio of 20% by 2024 and New Brunswick Power's 10 Year Plan includes a target to reduce debt by $1 billion to move closer to 20% by 2021.

Retained earnings cannot be relied upon in isolation when considering the financial position of Manitoba Hydro. Retained earnings must be considered relative to the size of assets on the balance sheet, that is, the equity ratio. In addition to the equity ratio, credit rating agencies and lenders rely on a suite of financial metrics such as Manitoba Hydro's other key financial ratios, including the interest coverage and capital coverage ratios, as well as other non-financial metrics.

Credit rating agencies view Manitoba Hydro's current low rates and reasonable regulatory framework as positive ratings considerations. However, it is important that credit rating agencies continue to view Manitoba Hydro's debt as self-supporting and that weakened financial ratios as a result of major capital investments and reinvestments do not negatively impact the credit ratings of the Province or Manitoba Hydro's borrowing costs.

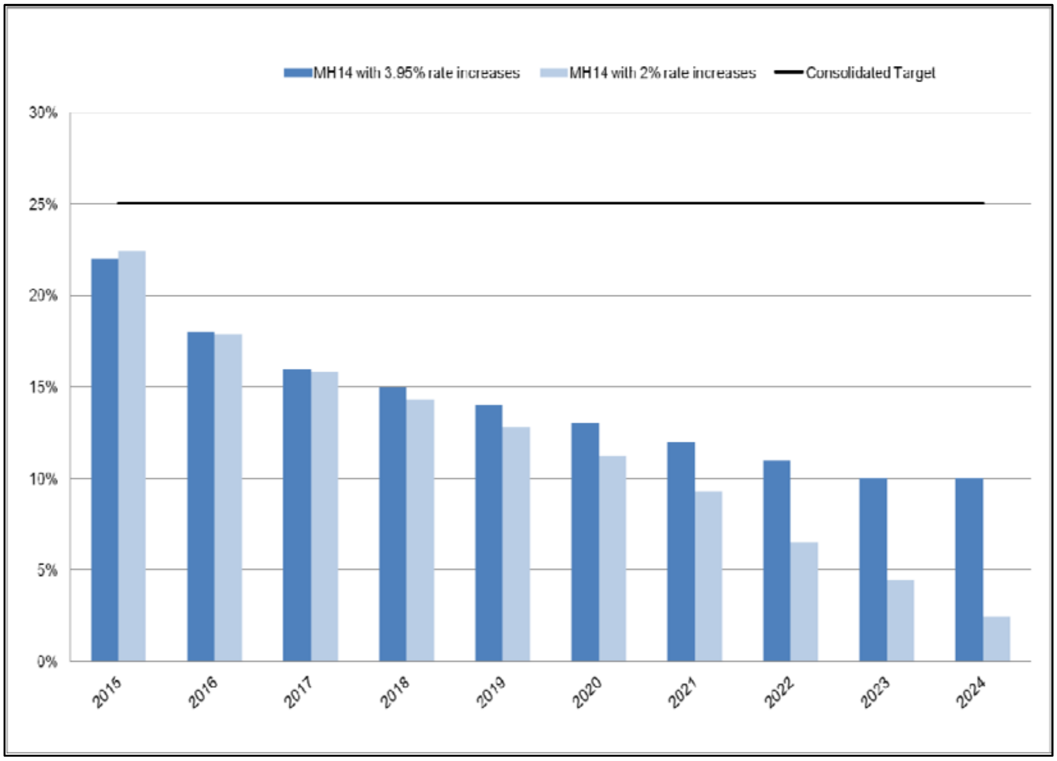
2.4 Inflationary Rate Increases Are Not Sufficient to Maintain Rate Stability for Customers

In PUB/MIPUG-9, it is noted that *"Mr. Bowman's primary conclusion regarding the above concerns is that there is ample basis for Hydro not to be granted a 3.95% rate increase, but rather that an increase more in line with inflation should be adopted."*

If Manitoba Hydro does not receive the proposed 3.95% rate increases, then there is a significant risk that the equity ratio may deteriorate to a point at which it may be very difficult to recover from, particularly considering the additional risk of water flow variability.

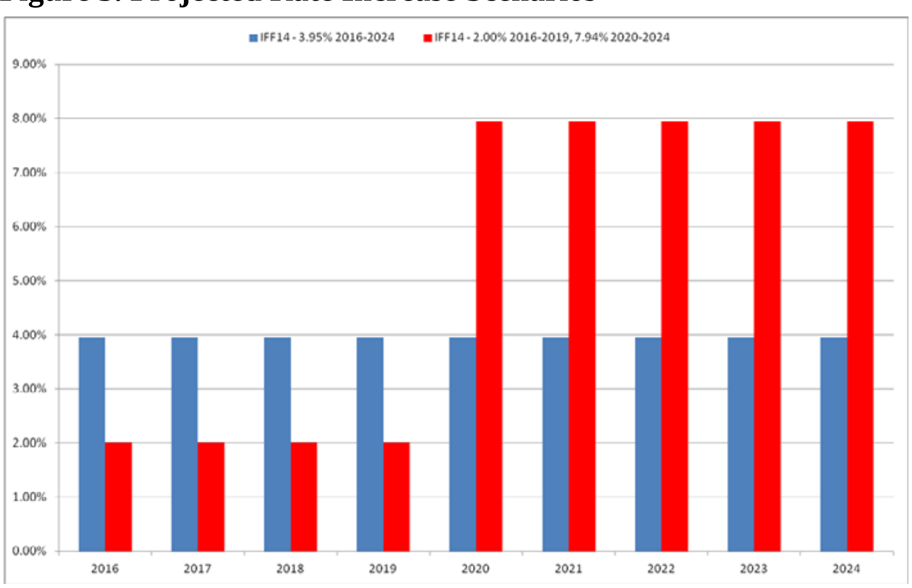
The following Figure 2 (Tab 2, page 41) demonstrates that with 2% rate increases, the deterioration of the equity ratio to 4% is substantial and would be detrimental to the financial strength of Manitoba Hydro. A rate increase that is based upon inflation does not allow the utility to recover its costs each year and will only result in additional borrowing requirements and financing costs in the future.

Figure 2: Projected Equity Ratio (2015-2024)



In addition, the impact of reducing or deferring the needed 3.95% rate increases will be to further stress Manitoba Hydro's financial position. Figure 3 below, from Tab 2, page 29 demonstrates that with 2% rate increases for the next 4 years, Manitoba Hydro would require 8% rate increases for the following five years to maintain the same level of retained earnings as in MH14.

Figure 3. Projected Rate Increase Scenarios



2.5 Lower Rate Increases Have a Significant Impact on Borrowing Requirements and Financing Costs

In the response to MH/MIPUG (BOWMAN)-3, Mr. Bowman "*…acknowledges $15-$45 million/year may be appropriate to include in rates. This compares to an estimated issuance of $2.4 - $3.2 billion a year in long-term debt over the next number of years. In other words, 99% of the forecast debt will need to be issued under either Hydro's rate increase proposal or Mr. Bowman*'s."

Mr. Bowman's assertion is very near-term in focus and underestimates the financial effects of compounding on both domestic revenues and finance expense over time. If Manitoba Hydro's proposed additional revenue of $57 million in 2016 is reduced to $32 million, or an equivalent rate increase in 2016 of 2% as suggested by Mr. Bowman, the debt issued in 2016 or 2017 significantly impacts revenue requirement over the ten year period. The following Figure shows the impacts of Mr. Bowman's proposed rate increase over the ten year period to 2024.

Figure 4. 2% Rate Scenario Impacts

($Millions)

2015/16 Rate Increase	Revenue Reduction 2016-2024	Incremental Finance Expense 2016-2024	Retained Earnings Reduction by 2024	Equity Ratio
MH14 3.95%				10%
2%	309	75	384	8%

As the above Figure demonstrates, even a one-time reduction in the proposed rate increase from 3.95% to 2% in 2015/16 would accumulate to a nearly $400 million reduction in retained earnings by 2024, and would reduce the equity ratio by full 2%, when the financing effects are included.

3.0 MANITOBA HYDRO'S SUSTAINING CAPITAL EXPENDITURES NECESSARY TO PROVIDE SAFE & RELIABLE SERVICE TO CUSTOMERS

3.1 Increases in Sustaining Capital Expenditures are Addressing Aging Infrastructure & System Capacity Needs

Mr. Bowman's evidence and responses to information requests have suggested that Manitoba

Hydro has not adequately justified the increases in expenditures for Sustaining Capital. Mr. Bowman's evidence provides at page 22 "*Without a clear and detailed explanation, such substantial changes over such a short time period are troubling. Consequently, the Board should be concerned with whether Hydro has provided sufficient justification to merit recovery of these costs through rates at this time*." In addition, in the response to COALITION/BOWMAN-3, Mr. Bowman states "*Absent information to explain at any useful level the basis for the sudden and substantial increases in capital spending…Failure by utilities to demonstrably support their expenditure claims otherwise leaves the Board with no basis to approve rate increases based on such claims.*"

Manitoba Hydro's need for investment in infrastructure is driven primarily by increased system capacity requirements and a requirement to replace its aging electric assets at accelerated rates. The magnitude of this investment is approaching a total of $5.7 billion by 2024 and is broad-based with significant capital investment requirements in the operational areas of generation, transmission and distribution. Over the ten year period through to 2024, approximately $400 million of additional investment for sustaining capital has been projected from CEF13 to CEF14 and over $1,100 million from CEF12 to CEF14. The required increases for sustaining capital expenditure have more than offset the removal of the overhead costs no longer eligible for capitalization under IFRS.

3.1.1 Generation Assets

Over the next ten years, generation assets will require investment of $1.3 billion or $130-$140 million per year. This investment is required to address the impacts of ageing infrastructure including the overhaul of stations along the Winnipeg River, management and mitigation of environmental and safety risks and restoration efforts to ensure continued reliability of smaller generation assets.

Replacement of Key Generation Assets

Approximately $450 million is for the replacement of aging assets within various generating stations including the replacement of generators, transformers, governors and breakers which contribute directly to a unit's ability to generate power. The replacement of these parts must be completed in advance of failure to avoid extended, unplanned outages, escalated repair costs and lost revenue. Capital investments to replace these drive train assets is related to their risk of failure.

Winnipeg River Generation Plant Overhauls

Approximately $400 million is required for the replacement or overhaul of aged generation plant including the Pine Falls, Slave Falls, Point Du Bois and Great Falls stations. These plants reside on the Winnipeg River, are between 60 to 104 years of age and now have drive train assets that are at a concerning risk of failure. Most of the overhauls are driven by the risk of an in-service failure of generators in poor condition, which could strand power for up to 2 years. As identified on page 30 of Tab 2, generation forced outage rates have increased significantly in the past four years. Without appropriate capital investment in the order of $50-$150 million to overhaul each plant, more units will be forced out of service resulting in lost generation for long durations.

Management and Mitigation of Environmental & Safety Risks

Additional capital investment is also required for the management and mitigation of environmental and safety risks and the refurbishment of infrastructure not directly related to a generating unit. This capital work is related to public safety around dams, environmental compliance for fish hatcheries, dam safety, water control, towns-site and staff house renovations and railway and road upgrades providing access to generating stations. These necessary investments are forecast to cost between $300-$350 million over the next ten years.

Restoration of Smaller Generation Assets

Approximately $200 million is required over the next decade with respect to restoration efforts to prolong the life of the smaller 60,000 generation assets in order to ensure these assets continue to operate in a reliable manner. Approximately 50% of this capital investment is required to address aging generation asset replacement while the balance is required to maintain supporting infrastructure such as roofing and water control.

3.1.2 Transmission Assets

Over the next ten years, transmission assets will require investment of $1.3 billion or $125-$150 million per year. Of the $1.3 billion, approximately 60% is for renewing transmission system and HVDC system assets with the balance required for growth in a number of areas of the transmission system where significant investments must be made in order to address higher than average load growth, deteriorating voltage, and/or the impacts of a stronger system following the completion of network upgrade and the Bipole III projects.

Transmission Line Asset Renewal

Approximately $151 million is required to renew transmission line assets to ensure that Manitoba Hydro can utilize the transmission lines at required ratings without endangering public safety. Through recent advancements in line surveying technology, Manitoba Hydro has determined that a portion of its transmission line spans will sag too low and violate CEA clearance criteria at required ratings. The transmission line asset renewal project will address this situation by replacing or modifying transmission line structures and conductors.

Replacement of Aging HVDC Assets

The investment required to renew aging HVDC assets is approximately $350 million. The HVDC system is critical to supplying power to Manitoba and our export customers. HVDC system outages can "bottle" northern generation, which represents 80% of Manitoba Hydro's output, and can have significant financial and system reliability impacts. The current Bipole II Valve Groups have experienced failures over the last several years, the worst of which resulted in a fire, significant equipment damage and lengthy outages. The Bipole II valve group thyristors are past end of life and will be replaced, along with their associated cooling systems, in the next ten years at a cost of approximately $230 million. Further, Manitoba Hydro expects to be in a similar position with the more numerous Bipole I valve groups over the next decade. Many of the HVDC Converter Transformers, which are needed to transfer energy between the DC and AC systems, are of original vintage and approaching or past end of life. Manitoba Hydro has currently budgeted $83 million to replace 10 of these transformers, which have multi-year procurement lead times due to the complexity of the design requirements.

Transmission System Capacity Requirements

In addition to asset renewal, there are a number of critical transmission system growth projects required to address increases in customer load and the impacts of a stronger system that necessitate increased equipment ratings. Approximately $360 million is required to address above average load growth in various areas of the province including the City of Winnipeg, Lake Winnipeg East, Morden/Winkler and the Brandon area. System firm capacity in various parts of the transmission system in these areas has been, or soon will be exceeded resulting in the potential for insufficient system voltages, thermal overloads on system equipment, which can result in the loss of equipment, significant safety concerns or rotating black outs. The urgency of investments related to load growth was highlighted during the winter of 2013/14, when serving load proved particularly difficult in the Lake Winnipeg East and Winkler/Morden areas. Deteriorating voltage support in the western part of the province can potentially impact local load and Saskatchewan exports.

Completion of a number of recent network enhancement projects and the Bipole III project will result in a large volume of transmission breakers functioning well beyond their interrupting capability, which poses a threat to employee and public safety as well as to adjacent equipment. Manitoba Hydro has budgeted to spend approximately $40 million to address this situation and replace breakers at various stations, including Dorsey, Laverendrye, McPhillips, and Brandon Victoria.

3.1.3 Distribution Assets

Approximately $2.2 billion of capital investment over the next 10 years or $200 to $270 million per year is required for distribution assets. The main drivers for this investment are capacity requirements due to domestic load growth both in Winnipeg and select rural areas, addressing the impacts of aging infrastructure, supporting customer growth, rural station & feeder development and distribution technology modernization.

Distribution System Capacity Requirements

Approximately 10% of the investment is required to increase electric capacity in the Winnipeg area, totaling in excess of $250 million through to 2020. Currently, 38% of distribution substations in urban Winnipeg are loaded beyond their maximum rating and there are no practical load transfer opportunities between stations to accommodate additional electricity demand with the City of Winnipeg. Operating stations beyond their technical design limitations also degrades substation component parts at a greater rate and increases the likelihood of large scale, long duration outages to a wide customer base. Manitoba Hydro requires capital investments in order to reduce the number of overloaded stations in Winnipeg by half by 2020 and to lower levels beyond this timeframe. Substations identified for development include Madison, St. Vital, Dawson Road and Adelaide. These substations are in proximity of increased commercial or residential development in various parts of the city.

In addition to major substation development projects, approximately $450 million of additional investment is required to replace or maintain distribution substations in Winnipeg as a result of increased electricity demand in localized areas due to residential, commercial or industrial growth and to replace component parts due to obsolescence and degradation. Notable examples include the refurbishment of the Martin Avenue substation to support residential growth in northeast Winnipeg, distribution consolidation and upgrades to service Health Sciences Centre institutional growth and installation of distribution supply centres (DSCs) in Waverley West area of southwest Winnipeg to accommodate rapid residential electricity demand.

Address Aging Distribution Infrastructure

The urgency to replace aging distribution assets is growing with each passing year. Approximately $700 million is required in the next decade to replace aging assets with current capital projections in excess of $1 billion over the next 20 years. Historically, the performance of Manitoba Hydro's distribution system has been very reliable. However, recently distribution system reliability performance has begun to degrade and asset condition is a contributing factor. Studies also indicate this overall degradation will exponentially grow unless the replacement of distribution assets accelerates.

Manitoba Hydro's electrical distribution system is comprised of eight critical assets: poles, overhead conductors, overhead transformers, streetlights, underground cable, duct lines, manholes, and padmount transformers. A significant portion of these critical assets are approaching the end of their serviceable lifespan and will require substantially higher replacement rates over the next 20 years. While asset maintenance programs have helped to prolong the life of these assets, the enormity of assets coming to end of their useful life makes aggressive capital investment to replace these assets the only viable option. Distribution asset categories requiring immediate capital investment due to worsening condition are underground cables, wood poles, streetlights and manholes. While the life expectancy of these assets in general ranges from 30 to 80 years, current replacement rates match assets resembling life spans of 100 to 500 years. Significant capital investment will help to replace distribution assets at rates that match their expected life.

Supporting New Customer Growth

As new customers request to be connected to the electric grid, Manitoba Hydro is mandated to install the necessary plant additions in order to service these requests. Approximately $550 million is forecast to be required over the next decade to support this new customer growth across the province, beyond what the Corporation receives in customer contributions for the electric service installations. The number of these service extensions amounts to over 5,000 each year.

Rural Station & Feeder Development

Approximately $200 million of capital investments are required over the next ten years to address rural capacity issues due to customer load growth in select geographic areas. While only 19 of 276 of rural distribution substations, or 7%, are operating beyond their maximum designed rating at the present time, this ratio will grow to 20% over the decade if enhancements are not made to existing substations or the feeders carrying the electricity to the customers. Higher profile areas that require immediate support consist of Steinbach, Winkler, Selkirk, Thompson and Brandon due to significant residential and commercial growth in those vicinities. Types of investments required to accommodate this growth and sustain reliability include replacing existing wood pole stations with distribution supply centres (DSCs), adding transformer banks and converting feeder lines to accommodate higher voltages.

Distribution Technology Modernization

A smaller but important component of capital investment is needed over the next 10 years to support the modernization of the distribution grid at a spend rate ranging from $5-$20 million per year or approximately $100 million over the next decade. This encompasses a distribution control system, system visibility and automation on distribution switches and feeders to enhance service reliability and improve operational performance. It is also required to provide greater sources of information and communication technology on the distribution system so that the timeliness of future capital development can occur with greater precision.

3.2 Other Canadian Utilities are also Experiencing the Need to Replace & Refurbish Aging Utility Assets

Projected increases in capital investment are not unique to Manitoba Hydro. As noted by the Conference Board of Canada, the required investment in Canada's electricity system between 2011-2030 is estimated at $350 billion. The following examples demonstrate that load growth and aging infrastructure is facing many utilities in Canada.

- BC Hydro is forecasting to invest approximately $1.2 billion a year on sustaining capital expenditures over the next three years. BC Hydro states "*Investments in these aging assets are required to meet targeted levels of customer and supply reliability. Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.*"[1]
- SaskPower is projecting to invest approximately $1 billion a year over the long term. Per SaskPower's 2014 Annual Report "*Expenditures related to load growth and aging infrastructure are driving increased demand for capital resources across our generation, transmission and distribution system. Like most other North American electric utilities, SaskPower has begun a significant program of reinvestment.*"[2]
- Toronto Hydro is also expected to invest approximately $0.5 billion a year over the next 5 years. Toronto Hydro has indicated in their current rate Application that "*The reliability of Toronto Hydro's distribution system is facing increasing pressure due to a large amount of aging and deteriorating infrastructure assets, legacy equipment, and obsolete devices.*"[3]
- Hydro-Quebec invested $3.9 million in Property, Plant & Equipment and Intangible Assets in 2014, $1.8 billion was directed at maintaining or improving asset quality.[4]

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[1] BC Hydro Service Plan 2014/15 – 2016/17, page 22. Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/bchydro-service-plan-2014-15-2016-17.pdf

[2] SaskPower 2014 Annual Report, page 38. Available at: http://www.saskpower.com/wp-content/uploads/2014-SaskPower-Annual-Report.pdf

[3] Toronto Hydro Distribution System Plan 2015-2019, Section E2, page 1. Available at: http://www.torontohydro.com/sites/electricsystem/Documents/CIR2015/EB-2014-0116_THESL_CIR_Exh2B_20150115.pdf

[4] Hydro-Quebec 2014 Annual Report, page 51. Available at http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report-2014.pdf

The need to replace and refurbish aging utility assets will place upward pressure on electricity rates across most jurisdictions in the coming years. Manitoba Hydro is not alone in needing to address the required investment in its electrical system through higher rate increases. While Manitoba Hydro will be required to gradually increase rates to pay for its increased investment in generation, transmission and distribution infrastructure, the electrical rate advantage enjoyed by energy consumers in Manitoba over those in most other jurisdictions is expected to continue.

4.0 MANITOBA HYDRO'S OM&A EXPENDITURES ARE MANAGED TO MINIMIZE IMPACTS ON RATEPAYERS

4.1 Manitoba Hydro has Implemented Effective Cost Control Measures to Minimize Growth in OM&A Expenditures

Mr. Bowman states on page 15 of his evidence that *"Hydro's Application has not provided an adequate explanation or justification for the continued increase in actual OM&A expenditures and why these amounts should be reflected in rates in the test year."* In addition, Mr. Bowman states on page 17 *"Overall, Manitoba Hydro's target of reducing EFTs by 300 positions does not appear to be fully realized in the test year."*

As demonstrated in the Figure below, Manitoba Hydro's year over year growth in OM&A, excluding accounting changes has been at or below inflation for most years. The actual average growth rate from 2009-2014 is equal to Manitoba CPI at 1.9%, while the projected average growth rate from 2014-2017 is below Manitoba CPI at 0.9%. These results demonstrate Manitoba Hydro's commitment to maintaining OM&A costs at or below inflation.

Figure 5. OM&A Percentage Growth

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2009-2014 Average Annual % Inc/(Dec)	2014-2017 Average Annual % Inc/(Dec)
OM&A % Change (excluding Accounting Changes)	2.7%	-0.1%	3.1%	2.4%	1.3%	0.6%	1.1%	1.1%	1.9%	0.9%
Manitoba CPI	1.9%	0.6%	2.8%	1.6%	2.4%	1.8%	1.9%	2.0%	1.9%	1.9%

Tab 5, Section 5.14 of the Application identifies numerous cost saving initiatives to manage both capital and operating expenditures, including Consolidation of Rural District Offices; Implementation of Mobile Workforce Management; Review of the Gillam Redevelopment & Expansion Project and Supply Chain Management Initiatives.

In order to achieve OM&A targets to 2016/17, Manitoba Hydro is reducing approximately

330 operational positions. As demonstrated on page 8 of Appendix 5.5, EFTs associated with operations and maintenance, and governance and support are decreasing. As provided in the response to PUB/MH II-42, the Corporation has already achieved a reduction of an additional 33 positions to the end of the third quarter over that which was planned in the 2014/15 fiscal year target.

Figure 6. Position (or Equivalent) Cost Reductions for 2014/15

Position (or Equivalent) Cost Reductions for 2014/15

	Actual Reductions achieved to December 2014	*Projected Reductions to March 2015	Higher/ (Lower) than Projected
President & CEO	0	2	(2)
General Counsel & Corporate Secretary	2	1	1
Human Resources & Corporate Services	40	33	7
Corporate Relations	3	3	0
Finance & Regulatory	5	4	1
Generation Operations	33	9	24
Major Capital Projects	5	1	4
Transmission	38	30	8
Customer Service & Distribution	35	46	(11)
Customer Care & Energy Conservation	18	16	2
Total	179	146	33

*Note - 6 of the 146 projected reduction will be achieved through other cost saving measures. The actual reduction of 179 to the end of December is entirely position reductions.

Manitoba Hydro's cost saving measures are effective and as referenced in PUB/MH I-72, OM&A expenditures to December 31, 2014 were below forecast. The outlook for the 2014/15 fiscal year is also expected to be below forecast, however, to a lesser extent than the December results.

4.2 Manitoba Hydro's Projected Vacancy Rates are Appropriate

Mr. Bowman states on page 17 of his evidence that *"Hydro has not provided a reasonable explanation for its forecast lower vacancy rates…"* and has indicated that a change in the vacancy rate to the historical average would result in a reduction in revenue requirement and enable a lower rate increase. In response to PUB/MIPUG-12, Mr. Bowman further states that "*using the average historical vacancy rate compared with Hydro's forecast vacancy rate results in an approximate reduction of revenue requirement in the range of $14 - $25 million per year*."

Manitoba Hydro's forecasted vacancy rate is appropriate for projected employment levels that reflect the Corporation's focus on cost containment. Manitoba Hydro has incorporated a reduction of more than 300 operational positions over the period of 2015-2017 in order to limit the average annual increases in OM&A to 1% net of accounting changes. As a result of reduced employment levels the vacancy rate will be lower than historic levels.

5.0 MANITOBA HYDRO'S ACCOUNTING POLICY CHOICES ARE FAIR AND DESIGNED TO MINIMIZE CUSTOMER RATE IMPACTS

Mr. Bowman contends that the cumulative effect of Manitoba Hydro's past and proposed accounting policy changes with respect to OM&A and depreciation are shifting costs to current ratepayers resulting in higher rates to customers. As per page 24 of Mr. Bowman's testimony, he states "*…the PUB must primarily concern itself with ensuring the overall approach is principled and reasonable and results in a fair matching of cost profiles and benefits for ratepayers*". His testimony, however, selectively accepts only those accounting changes that decrease costs and ignores the fact that the PUB accepted Manitoba Hydro's prior accounting changes for rate-setting purposes in Order 43/13.

5.1 The PUB Accepted Manitoba Hydro's Prior Accounting Changes for Rate-Setting Purposes in Order 43/13

On page 6 of Mr. Bowman's testimony he states that the, "*Cumulative effect of accounting changes are not adequately justified in the context of current day rate payer.*" The term "cumulative" as utilized by Mr. Bowman refers to both past accounting changes implemented under CGAAP as well as those proposed under IFRS. Mr. Bowman also argues that these changes are resulting in substantial increases in costs in the test years.

Prior to this application, Manitoba Hydro made accounting estimate changes with respect to reducing the amount of overhead capitalized in property, plant and equipment and reducing depreciation rates for certain assets found to be surviving longer than initially estimated. Reductions in the amount of overhead capitalized had been recommended by the PUB in previous orders. These accounting changes were extensively reviewed during Manitoba Hydro's 2012/13 and 2013/14 GRA and have been accepted by the PUB for rate-setting purposes as per the findings on page 14 of Order 43/13, which reads as follows:

> "*The Board understands that Manitoba Hydro has been making changes to its accounting policies since 2007/08 to be more consistent with other electric utilities as well as to be consistent with International Financial Reporting Standards. The Board in past orders had expressed concern with the level of capitalization and Manitoba Hydro has begun to address these concerns. In the Board's view, Manitoba Hydro's proposed accounting changes are appropriate for the test years.*"

As such, any revisions to prior accounting policy changes for rate-setting purposes as suggested by Mr. Bowman would be inconsistent with the past decisions and recommendations of the PUB.

5.2 The Proposed Rate Increases are Not Being Driven by Aggressive Accounting Policy Selection

On page 4 of Mr. Bowman's testimony, he states that "*changes to accounting methods resulting in effects to depreciation, OM&A and capital expenditures that have material effects on the timing of when these costs are recovered through rates, i.e., these accounting changes are shifting costs to current ratepayers and increasing the rate increases requested today in the Application.*"

In previous rate proceedings, concerns have been expressed that Manitoba Hydro's rate increases are being driven by aggressive accounting policy choices, in particular the expensing of additional overheads and the proposed change to the depreciation methodology.

There are a number of prospective accounting changes that Manitoba Hydro is making for financial reporting purposes in 2014/15 and 2015/16. The most significant of these include the implementation of a comprehensive depreciation study in 2014/15 and further changes to the level of capitalized overhead and deprecation methodologies as part of the implementation of IFRS in 2015/16.

Manitoba Hydro's approach towards ensuring fairness in customer rates is balanced in that it considers the impact on revenue requirement of all the accounting changes. The net accounting impacts as identified in Appendix 5.7 result in decreases to revenue requirement of $25 million in 2014/15 and $4 million in 2015/16 and 2016/17, respectively as illustrated in the figure below.

Figure 7. Accounting Policy and Estimate Changes

Accounting Policy & Estimate Changes Electric operations (in millions of $'s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OM&A Expense Changes	-	51	56	57	58	58	59	60	61	62
Depreciation Expense Changes	(25)	(53)	(57)	(60)	(76)	(86)	(96)	(101)	(103)	(105)
Other	-	(3)	(3)	(4)	(3)	(3)	(4)	(4)	(3)	(5)
Total Increase (Decrease) in Revenue Requirement	(25)	(4)	(4)	(7)	(22)	(31)	(41)	(45)	(46)	(48)

Mr. Bowman's suggestion that accounting changes are driving the need for rate increases is unfounded.

5.3 The PUB Rejected the Intervener's Recommendations to Adjust Accounting Policies to Lower Rate Increases in Order 43/13

A common theme exhibited in the testimony of Mr. Bowman and throughout the Information Request's received by Manitoba Hydro is to select accounting policies that reduce non-cash expenditures (e.g. depreciation expense) as a means to improve net income and reduce customer rates. Mr. Bowman's testimony argues that the ELG method should not be adopted for rate-setting purposes and that the CGAAP ASL method should be retained. Mr. Bowman views this accounting choice as a means by which to increase net income and thereby reduce customer rates.

Manitoba Hydro is concerned with the approach implied by Mr. Bowman to choose accounting policies with the express purpose to improve net income and reduce customer rates with little understanding as to how these changes impact the cash flow and financial strength of the Corporation. The reduction in depreciation expense resulting from the continued use of the CGAAP ASL method does not result in a reduction in cash outflows as depreciation is a non-cash expense. The corresponding reduction in customer revenue does, however, result in a cumulative reduction in cash inflows of $1.2 billion (excluding carrying charges) through to 2034 which will result in an increase in debt levels.

As outlined in Tab 2 of this Application, Manitoba Hydro is entering a period of extensive capital investment and re-investment in its infrastructure. The vast majority of this investment will be funded through debt financing resulting in debt levels that are unprecedented in Manitoba Hydro's history. The additional $1.2 billion of debt will further weaken the financial strength of Manitoba Hydro and increase the risk of rate volatility to customers.

At the 2012/13 and 2013/14 GRA, MIPUG and CAC recommended for rate-setting purposes that the PUB not accept overhead changes and remove net salvage from depreciation rates in advance of IFRS conversion in order to justify lower rate increases. This approach was explicitly rejected by the PUB in their findings on page 10 of Order 43/13 from Manitoba Hydro's 2012/13 and 2013/14 GRA, as follows:

> *"Interveners recommended various accounting changes to lessen rate increases over the test years. The Board rejects this approach as it would have the effect of reducing Manitoba Hydro's revenues, weakening its financial situation, and increasing borrowing costs. It is important that Manitoba Hydro remain a financially strong and viable organization."*

Manitoba Hydro concurs with the PUB's rejection of proposed changes in its accounting policies for rate-setting purposes that result in higher debt levels and weaken the financial strength of the Corporation.

5.4 Recognition of Regulatory Deferral Balances Lessens Differences between Expenses Recognized for Financial Reporting and Rate-Setting Purpose

Mr. Bowman and Ms. Lee recommend the continued use of the CGAAP ASL method for rate-setting purposes. On page 14 of Ms. Lee's testimony she states, *"It is my opinion that Hydro should be allowed to implement ELG for IFRS purposes if it deems appropriate but continue with the ASL procedure for rate setting purposes."*

Both Mr. Bowman and Ms. Lee fail to recognize that under IFRS, differences between the accounting for financial reporting and rate-setting purposes must be captured in regulatory deferral accounts and presented in the general purpose financial statements. The application of interim standard IFRS 14 *Regulatory Deferral Accounts* requires that the standard be applied to all or none of an entities regulated activities. IFRS 14 paragraph 8 reads as follows, *"An entity that is within the scope of, and that elects to apply, this Standard shall apply all of its requirements to all regulatory deferral account balances that arise from all of the entity's rate-regulated activities."*

If Manitoba Hydro were to continue to use the CGAAP ASL method without net salvage for calculating depreciation for rate-setting purposes, Manitoba Hydro would continue to request rate increases of 3.95%. As outlined in the response to PUB/MH-II-21b, the cumulative difference in depreciation expense between the ELG procedure used for financial reporting and the ASL method used for rate-setting is captured in a regulatory deferral account and must be amortized annually over the periods in which the amount can be recovered in customer rates. Under the scenario, customer rate increases are projected at 3.90% annually from 2018 through to 2031 and 2.0% thereafter in order to achieve a 25% equity ratio by 2034, assuming a reduction in depreciation from the continued use of CGAAP ASL in conjunction with the amortization required for the new regulatory deferral account. The Figure below provides the results of this scenario and demonstrates that the $1.2 billion reduction in depreciation expense through to 2034 by continuing with the CGAAP ASL method is primarily offset by the $0.9 billion increase resulting from the amortization of the deferred regulatory asset and as such, does not significantly impact the requested rate increases.

Figure 8. CGAAP ASL without Net Salvage Scenario

Account	March 31, 2034
Retained Earnings (MH14)	**5 557**
Depreciation expense reduction – continue with CGAAP ASL (no net salvage)	1 238
Depreciation expense increase – amortization of Deferral Account (10 year amortization period)	(921)
Reduction in customer rate revenue via 3.90% increases	(184)
Increase in Finance expense for higher debt levels	(81)
Increase in Capital taxes for higher debt levels	(23)
Reversal of the 2015 Retained Earnings adjustment for the change to ELG depreciation	33
Ending Retained Earnings	**5 619**
Net change in Retained Earnings	**62**

5.5 A Single Set of Financial Information Provides Efficiency, Transparency & Reliability for Rate-Setting

Both Mr. Bowman and Ms. Lee imply in their testimony that Manitoba Hydro should produce two sets of financial information; one set for financial reporting based on an IFRS compliant depreciation procedure, and one set for setting customer rates based on the existing CGAAP ASL depreciation procedure. In Ms. Lee's testimony she states, "*I do not understand the adversity to keeping two sets of books as this can also be handled by the computer.*" Mr. Bowman also states that, "*It is noted that reporting for rate regulation purposes need not strictly follow financial report requirements moving forward; however, Hydro has an aversion to the "two sets of books" solution.*"

5.5.1 A Single Asset Sub-ledger is More Efficient

It is important to clarify what is meant by two sets of books and highlight the significant implications for Manitoba Hydro, its customers, and the users of its financial statements. The issue of two sets of books in effect, means the development and maintenance of separate accounting records and calculations to support the recognition of the balances captured in the regulatory deferral accounts. The extent of the resources and cost to maintain separate accounting records will depend on the nature of the item.

As it pertains to the calculation of depreciation for Manitoba Hydro's $ 16 billion of plant assets, the time and resources required to maintain separate ledgers is substantial.

Proponents of maintaining two sets of books tend to have a very short term focus and fail to consider the implications of having to maintain and reconcile such differences 20 years or more after the change. As outlined in Manitoba Hydro's response to PUB/MH-II-21c, a regulatory deferral account would require the recognition of all transactions associated with depreciation expense and gains and losses on asset retirements to be recognized in separate sub-ledgers, as the amounts for depreciation expense and gains and losses would be different under the two methods. The process for maintaining two Property, Plant & Equipment ("PP&E") sub-ledgers will be extremely onerous, time consuming and costly given the thousands of transactions that are recorded each year. Manitoba Hydro currently has 93,000 assets with values in its sub-ledger books which are projected to almost double in the next 20 years. In addition, the extent of external audit work required will double as will be the requirement to perform two depreciation studies. The following is a summary of the ongoing administrative efforts impacted by maintaining two separate plant sub-ledgers:

- Monthly and quarterly financial reports;
- Annual forecasting requirements;
- Quarterly/annual reconciliation of PP&E related accounts;
- Annual audit of depreciation rates / expense, asset retirement gains and losses, and PP&E net book value balances; and
- Depreciation studies

Ms. Lee's and Mr. Bowman's evidence demonstrate that they are not familiar with the requirements to develop, implement and maintain two sets of ledgers with respect to the calculation of depreciation expense for a large utility with thousands of assets recorded in its sub-ledgers.

5.5.2 A Single Set of Financial Statements Provides Transparency & Reliability for Rate-Setting Purposes

Another important consideration is that the IFRS standard IFRS 14 *Regulatory Deferral Accounts* is only an interim standard, pending the outcome of the IASB's projects on Rate-regulated Activities over the next five years. Should the IASB conclude at the end of these projects that regulatory deferral accounts can no longer be recognized under IFRS for financial reporting purposes, Manitoba Hydro would have to write off its regulatory account balances to retained earnings.

Manitoba Hydro does not support the concept of issuing two complete different sets of financial statements due to the confusion associated with users, including the PUB, the Manitoba Hydro-Electric Board, credit rating agencies and other stakeholders, in reviewing multiple sets of financial information in order to make decisions, evaluate financial performance and assess rate requirements. As noted above, there are significant administrative costs associated with reconciling the different sets of financial information and maintaining duplicate transactional accounting records. This requirement would add to the regulatory compliance costs that customers ultimately must bear without any additional benefit.

A single set of financial statements improves the transparency of the rate-setting process by aligning the basis to set rates with the financial reporting results. In addition, the use of audited financial information in the rate-setting process improves the reliability of the information.

5.5.3 CAMPUT Supports a Single Set of Financial Statements to Best Serve the Public Interest

Manitoba Hydro's concerns are consistent with the August 30, 2013 letter from Canadian Association of Members of Public Utility Tribunals ("CAMPUT") to the IASB regarding the IASB Exposure Draft on Regulatory Deferral Accounts (as provided in the response to PUB/MH-II-21c). The letter describes the views and concerns of regulators with respect to maintaining two separate sets of financial statements. Manitoba Hydro notes the following relevant excerpts from the CAMPUT letter, with emphasis added by underlining:

> *"The interim Standard resolves one major problem for entities with rate-regulated operations. <u>Our observation is that, without the interim Standard, these rate-regulated entities will be required to provide two sets of financial statements</u>, as has happened in some other jurisdictions and as was*

> *acknowledged by the IASB9: one to meet general purpose financial reporting requirements under IFRS; and, the other to present to the rate regulator for purpose of (i) requesting rate adjustments, (ii) regulatory accounting and rate-making, and (iii) regulatory reporting. As regulators, we find it <u>unsatisfactory and not serving the public interest</u> <u>if there are two views of economic reality of entities with rate-regulated operations</u>. Rate regulators are aware that their actions have significant economic impact, including investment, lending and consumer prices. The IASB has acknowledged that many of rate-regulated entities argue that recognizing such balances as assets and liabilities would provide more relevant information and would be a more representationally faithful way of reporting their rate-regulated activities. Some of these utilities had to eliminate regulatory deferral account balances from the statement of financial position when they adopted IFRS and do not recognize such balances in IFRS financial statements. <u>It behooves the accounting profession to find the appropriate ways to ensure all economic events are reflected in the base numbers reported in general purpose financial statements</u>. <u>Requiring rate-regulated entities to leave certain economic events outside the purview of the financial statements, or at best relegated to note disclosure, is not good enough for regulatory actions that affect prices. Furthermore, exclusion of certain economic events would not serve the needs of users of the financial statements.</u>*
>
> *Finally on this point, <u>the results of having two views</u> <u>will add confusion and unnecessary complexity and higher cost to the rate-regulated entities and their customers such as maintaining two sets of books.</u> <u>Furthermore, the investors or the lenders of the rate-regulated entities will find it confusing to decide which set of financial statements to use when monitoring financial performance to judge the financial soundness of the enterprises.</u> The IASB's proposed interim Standard addresses the above concerns. Therefore, we support the IASB's development and application of the interim Standard."*[5] *<u>(page 3)</u>*

Manitoba Hydro supports the comments made in the CAMPUT letter that publishing two separate complete sets of financial statements will only add confusion and unnecessary complexity and will not serve the needs of the various users of the financial statements. Given that the cumulative effect of the accounting changes projected by Manitoba Hydro do not have a negative impact on customer rates, Manitoba Hydro does not see the need for separate

[5]CAMPUT Letter to IASB, dated August 30, 2013. Available at: http://www.camput.org/wp-content/uploads/2013/09/2013-08-30-Letter-on-ED-Regulatory-Deferral-Accounts.pdf

sets of sub-ledgers, new regulatory deferral accounts or separate sets of financial statements for rate-setting purposes.

5.6 There is No Need for A Second Set of Regulatory Financial Statements under the Cost of Service Rate-setting Methodology

The need for separate financial statements or accounting sub-ledgers is not necessary under the cost of service rate-setting methodology that is used to set electric rates in Manitoba.

The cost of service approach applied in Manitoba does not determine rates based strictly on changes in costs and on an established capital structure and return on equity. Rather, the cost of service methodology coupled with Manitoba Hydro's approach of implementing regular and reasonable rate increases has the flexibility to recognize changes in costs and levels of retained earnings and transition these changes into rates gradually over time, while at the same time ensuring the maintenance of an adequate financial structure over the long-term. This approach serves to protect customers from sudden or large rate increases and makes a set of financial statements or separate sub-ledger for rate-setting purposes unnecessary.

6.0 MANITOBA HYDRO'S PROPOSED DEPRECIATION CHANGES ARE APPROPRIATE FOR RATE-SETTING IN A HYDRO-ELECTRIC UTILITY

In addition to the rebuttal below, please refer to Appendix A for the expert rebuttal of Mr. Kennedy with respect to the evidence submitted by Mr. Bowman and Ms. Lee. Mr. Kennedy's addresses concerns with respect to the level of detail provided, sensitivity of IOWA curves, implementation of ELG, and the appropriateness of net salvage in depreciation rates.

6.1 The ELG Method Promotes Intergenerational Equity for Rate-Setting Purposes

Mr. Bowman states that, "*The Equal Life Group (ELG) method of depreciation as proposed in the Application imposes unfair added costs on current ratepayers and therefore should not be adopted, and the Average Service Life method should be retained, consistent with other Crown owned and hydro dominated utilities.*" This is consistent with the testimony of Ms. Lee.

On page 6 of Mr. Bowman's testimony he argues that, "*Manitoba Hydro is proposing to adopt an approach to depreciation rate calculation that includes,.…, an element that will substantially accelerate its collection of depreciation expense and impose unnecessarily high costs on today's rate payers without any corresponding increase in benefits related to the* *underlying assets."*

Manitoba Hydro does not agree with the recommendation to continue with the CGAAP Average Service Life method for rate-setting purposes. The ELG method is more representative of an asset's annual depreciation than an ASL method when applied to a group of assets with a wide dispersion in service lives, as is the case for Manitoba Hydro's assets. Manitoba Hydro's change to the ELG method is the preferred alternative for both financial reporting and rate-setting purposes as it improves inter-generational equity, by matching the amortization of cost to the life of the assets in use, ensuring that each generation of ratepayers is charged only for assets of benefit to that generation.

Mr. Bowman's argument that the ELG procedure will substantially "accelerate" depreciation and impose higher costs on today's rate payers for no additional benefits is incorrect. The increase in depreciation expense referred to by Mr. Bowman is not an acceleration of depreciation, but is the impact of depreciating assets with lives shorter than the average service life of the pool over a more representative shorter service period. In this respect, the ELG method promotes an improved matching of costs to the periods of benefit whereas under the CGAAP ASL method, current rate payers are being undercharged for the benefits they receive today and in effect, are being subsidized by future rate payers. Although convenient and easier to administer, the CGAAP ASL method is not promoting intergenerational equity to the same degree as the ELG method.

6.2 The ELG Method Provides Consistent Results with the Methods Used by Other Hydro-Electric Utilities

Mr. Bowman argues on page 25 of his testimony that there is no precedent for using the ELG method, "I*t is concerning that Hydro is so adamant about changing to this method of depreciation when it hasn't been proven effective or even relevant to any other electric utility with long-lived assets, especially for rate setting but also for financial reporting purposes."*

As outlined in the response to PUB/MH-I-42b, the ELG procedure is used throughout many jurisdictions in North America. The ELG procedure has been used by Newfoundland Power since 1983. In making their decision to allow Newfoundland power to fully adopt the ELG method for all property, plant and equipment in 1983, the Board of Commission of Public Utilities in Newfoundland stated in its order that it, *"...agrees that rates of depreciation based on the [ELG] procedure is the best method of recovering invested capital over the useful life* *of the plant. Having reached this conclusion, the [ELG] procedure stands the test of a reasonable and prudent expense properly charged to operating account."*[6]

Mr. Bowman's argument that Manitoba Hydro should use the ASL method to be consistent with other crown utilities ignores the fact that the nature and level of asset componentization varies between utilities, and many of the larger Crown utilities (BC Hydro, SaskPower and Hydro Quebec) have historically maintained a greater level of asset componentization and detailed asset records than Manitoba Hydro. Such utilities are applying the ASL method based on a "unit" accounting approach as opposed to a "group" accounting approach and as such, the calculation of depreciation is more consistent with the requirements of IFRS. As demonstrated in Appendix 11.49, the differences in depreciation expense between the ELG method and ASL method are reduced when the ASL method is applied to a greater level of asset componentization. Manitoba Hydro's change to the ELG method of depreciation will make its depreciation expense calculation more comparable with the ASL unit approach to depreciation as calculated by the other crown utilities in Canada as referenced by Mr. Bowman.

6.3 The ELG Method is Appropriate for Both Long & Short Lived Assets

Mr. Bowman states on page 24 of his testimony that, *"The Equal Life Group (ELG) approach to depreciation does not match the economic cost curve of long-lived hydroelectric generation assets, a concept imperative to setting fair rates."*

Just as the ELG method of depreciation is more robust and accurate for assets that have a service life shorter than the average life used to calculate depreciation for a pool of assets, the ELG method is more accurate for assets that have a longer life than the average for the pool. By its very nature, the ELG procedure places assets into sub-groups of similar service lives such that assets are amortized over their respective service life as opposed to an average for all the assets in a pool.

Mr. Bowman's argument that the ELG method is not appropriate for long-lived assets is inconsistent with the purpose of depreciation. His argument is not premised on the depreciation principle of recognizing a plant asset's cost over the period in which it is consumed, but is instead premised on his presumption that the economic value (i.e. profitability) of hydraulic generation assets increase over time. Since the ELG method results

[6] Page 21, Newfoundland and Labrador, An Order of the Board of Commissioners of Public Utilities No. P.U. 47 (1982)

in higher depreciation in the early years of a pool of assets, Mr. Bowman argues that proper matching does not occur under ELG.

As outlined in section 4.3 of Appendix 11.49, the IASB has formally rejected the concept of depreciating an asset based on the pattern of revenue it generates. The IASB explicitly prohibits revenue from being used as a basis for depreciation because factors other than the consumption of an asset affect revenue. The IASB points out that although depreciation and revenue share some common attributes, depreciation is an estimate of the benefits consumed from an asset in the period whereas revenue reflects the output of the asset, but also reflects the impact of other factors that do not affect the physical consumption of an asset.

Manitoba Hydro concurs with this argument as the profitability of a hydraulic generating station is dependent on a number of variables that are not related to the physical consumption of the plant such as future electricity prices, exchange rates, and water levels.

Using a depreciation method that is intended to match depreciation rates to the profitability of a plant asset would require ongoing adjustments to depreciation rates to accommodate changes in other forecast variables such as market prices and water levels which would only result in an increased level of subjectivity and volatility in depreciation expense. This would be problematic for rate-setting purposes.

6.4 The ELG Method is Consistent with Ms. Lee's Recommendations in Selecting a Depreciation Methodology

On page 14 of Ms. Lee's testimony, she states that, "*It is my opinion that companies should componentize, subcategorize, or subaccount as the need arises for separating out investments expected to live in a different fashion from the group.*"

Manitoba Hydro notes the similarities between the evidence of Ms. Lee and the more explicit depreciation requirements of IFRS section IAS 16 *Property, Plant & Equipment.* As provided in response to MIPUG/MH-I-17a, excerpts from IAS 16 read as follows:

> **43** *Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately*.

In developing the IAS 16 standard, the IASB had the following comments in their Basis for

Conclusions:

Depreciation: unit of measure

> *BC26 The Board's discussions about the potential improvements to the depreciation principle in the previous version of IAS 16 included consideration of the unit of measure an entity uses to depreciate its items of property, plant and equipment. Of particular concern to the Board were situations in which the unit of measure is the 'item as a whole' even though that item may be composed of significant parts with individually varying useful lives or consumption patterns. The Board did not believe that, in these situations, an entity's use of approximation techniques, such as a weighted average useful life for the item as a whole, resulted in depreciation that faithfully represents an entity's varying expectations for the significant parts.*

As outlined in Appendix 11.49 to this application, Manitoba Hydro is adopting the ELG method as an efficient means by which to comply with the more strict componentization requirements of IFRS. Given that the ELG procedure subdivides a group of property into sub groups having equal service lives, and calculates depreciation for each sub group separately, the methodology enables Manitoba Hydro to meet the strict requirements of IFRS without having to further increase the number of its asset components. In effect, the ELG procedure calculates depreciation expense consistent with the recommendation of Ms. Lee as it is calculated at the sub-account level for investments expected to have a service life different than the average resulting in a better matching of costs and benefits. Therefore, the depreciation method chosen by Manitoba Hydro for compliance with IFRS meets the requirements of Ms. Lee in selecting a depreciation method and as such, a separate method for rate-setting purposes is not required.

6.5 Manitoba Hydro has Enhanced its Retirement Information to Reduce the Extent of Use of Statistical Data in Depreciation Studies

The testimony of Mr. Bowman and Ms. Lee argue that Manitoba Hydro does not have sufficient historical retirement data from which to derive appropriate life curves. Mr. Bowman states on page 25 of his testimony that, "*Additionally, the cost curves and asset lives detail used in the current depreciation study need to be adequately supported based on actual information of Hydro's assets.*" On page 12 of Ms. Lee's testimony, she states, "*It is clear that for many of Hydro's accounts, there has been insufficient retirement activity from which to derive a future pattern.*"

Both the testimony of Mr. Bowman and Ms. Lee are based on incorrect assumptions with respect to the extent of Manitoba Hydro's actual historical retirement data. Since the 2005 study, Manitoba Hydro has undertaken extensive efforts to compile historic retirement data for those asset groups where historical records were missing. Such efforts were initially implemented for the 2010 depreciation study as new asset components were established for use under the ELG method so as to ensure compliance with the more strict depreciation requirements of IFRS. The process for doing so included thousands of hours of staff time to convert information from historical manual accounting ledger books dating back to the 1940s. This process also involved extensive discussion and analysis with Manitoba Hydro engineers to confirm the results of the data compilation.

In response to PUB/MH-II-59a, Manitoba Hydro provided the costs pertaining to the conversion to ELG which included $1.7 million of costs to prepare / review historical accounting records for existing and new asset components and to re-allocate costs between component groups. As further noted in the response to PUB/MH-II-59a, the effort of asset conversion is not expected to be completed until sometime in 2015. For the 2014 depreciation study, only ten depreciation accounts required historical records to be statistically generated.

6.6 Manitoba Hydro has Managed the Rate Impact of ELG through the Removal of Negative Salvage Value in Depreciation Rates

Mr. Bowman argues on page 26 of his testimony that "*the elimination of net salvage costs should be accepted because it was not taking into account inherent economic value associated with hydroelectric sites….*" In addition, Mr. Bowman states that, "*Net salvage inaccurately added costs to ratepayers today to pay for dismantling that would not occur in the future.*"

The collection of costs required to remove an asset from service (i.e. negative salvage) is a valid regulatory construct and is consistent with the regulatory principle of intergenerational equity which ensures that rate payers who benefited from the asset are charged with the total costs, including the cost to remove the asset from service. This approach to matching the costs associated with retiring an asset to the years of benefit derived from the asset is fair and reasonable and has been a PUB approved practice for rate-setting purposes for Manitoba Hydro's electric operations for the past 20 years.

Manitoba Hydro had made a policy decision in 2010 to move to the Equal Life Group depreciation method to comply with the transition to IFRS. In making that policy decision, Manitoba Hydro recognized that there would be an initial increase in depreciation expense.

At that same time, Manitoba Hydro made an explicit policy decision to remove net salvage from depreciation rates upon transition to IFRS to manage both the financial reporting and rate-setting impacts of the move to ELG.

As noted in the table below the decision to eliminate net salvage in depreciation rates results in a cumulative reduction to depreciation expense in excess of $2 billion through to 2034, which is more than sufficient to offset the revenue requirement impacts of the adoption of ELG. This approach makes Ms. Lee's recommendation for a three-year phase-in period of ELG for rate-setting purposes unnecessary.

Figure 9. Depreciation Policy & Estimate Changes

Depreciation Policy & Estimate Changes **Electric Operations (in millins of $s)**												
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025-2034**	**Total**
Change in service life - (2014 Depreciation Study)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)	(391)	(746)
Overhead Ineligible for Capitalization	-	-	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)	(244)	(310)
Elimination of Provision for Asset Removal	-	(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)	(1,309)	(2,141)
Change in Methodology (ELG)	-	36	38	41	49	55	63	67	68	69	752	1,238
Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**	**(60)**	**(77)**	**(86)**	**(96)**	**(102)**	**(105)**	**(106)**	**(1,192)**	**(1,959)**

Manitoba Hydro recommends that the PUB should consider the overall impact of the collective depreciation changes for rate-setting purposes, rather than concentrating only on the impact of ELG as Mr. Bowman has in his evidence.

6.7 Manitoba Hydro's Proposed Treatment of the Accumulated Depreciation Surplus is Fair to Ratepayers

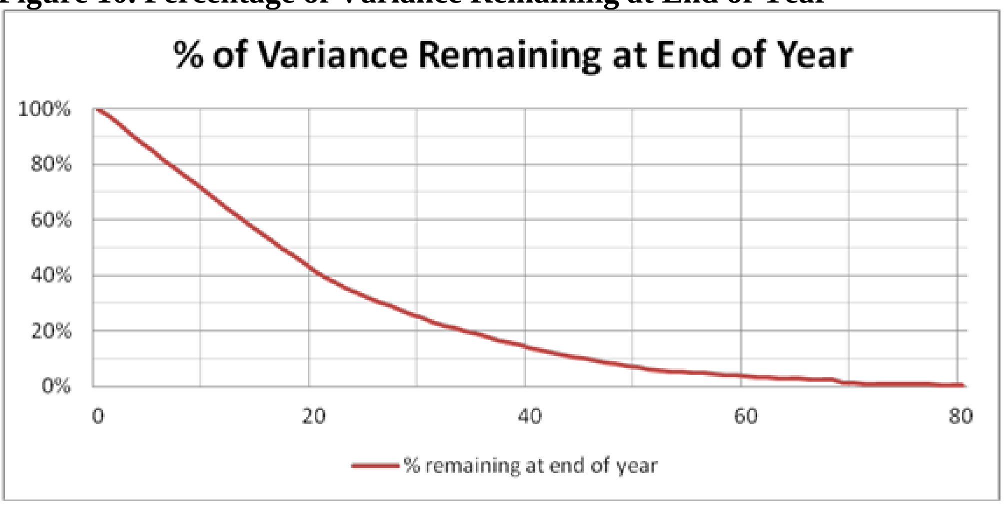
In the testimony of Ms. Lee and in MIPUG's response to PUB/MIPUG-15, both suggest the possibility of amortizing the depreciation surplus over a period shorter than the average remaining life of the assets to which the surplus pertains. Despite these suggestions, both Ms. Lee and Mr. Bowman ultimately support Manitoba Hydro's proposed approach. In her response to PUB/MIPUG/COALITION (Lee) 7, Ms. Lee states the following with respect to Manitoba Hydro's proposal to amortize the depreciation surplus over the remaining life of the specific depreciable asset accounts to which it pertains, "*Considering the benefits the future expenditures will bring and the increasing economic benefits of the existing Hydro plants, recovery over the remaining life is appropriate.*" In MIPUG's response to PUB/MIPUG-15 it states, "*In the end, however,… Mr. Bowman does not take issue with the proposal by Hydro to use remaining life due to practical reasons of rate/cost stabilit*y."

Manitoba Hydro notes that its approach to amortizing the 2010 depreciation study surplus to the benefit of customers over the remaining life of the specific depreciable asset accounts was accepted by the PUB in Order 43/13 on page 18 as follows:

> *"The Board accepts the depreciation rates applied April 1, 2011, which rates reflect the changes in service lives and the true-up of the accumulated depreciation surplus for the test years."*

In Manitoba Hydro's response to MIPUG/MH-I-20b, Manitoba Hydro points out that with respect to the amortization of the surplus, if there were no additions to the asset base after March 31, 2014, and provided retirements adhered to those predicted by the assigned depreciable lives and IOWA curves, Manitoba Hydro would expect to amortize 75% of the variance within 30 years, as identified in the Figure below.

Figure 10. Percentage of Variance Remaining at End of Year



7.0 LOW-INCOME AFFORDABILITY PROGRAM

7.1. Manitoba Hydro Offers a Strong Suite of Programs that are Coordinated to Assist Its Low-Income Population

Manitoba Hydro currently has two programs available to assist low income customers: the Affordable Energy Program (AEP), which provides assistance in completing energy efficiency upgrades to low income homeowners and the landlords of low income tenants, and the Neighbours Helping Neighbours program, which is administered by the Salvation Army and is designed to support people experiencing personal hardship or crisis who are unable to pay their electricity bill. Mr. Colton criticizes Manitoba Hydro's efforts in coordinating and integrating assistance programs for inability-to-pay customers. At page 27 of his evidence, Mr. Colton states: *"There is virtually no coordination between Neighbours Helping*

Neighbours ("NHN") and the Company's Affordable Energy Program ("AEP")…"

Contrary to Mr. Colton's views, Manitoba Hydro extensively coordinates the Affordable Energy Program ("AEP") with the NHN Program. For example, Manitoba Hydro directly targets customers in arrears through its autodialer campaign, receives referrals from internal Credit & Recovery staff and NHN grant recipients have a mandatory requirement to apply to the AEP. Manitoba Hydro's coordination of these activities was confirmed by Dunsky Energy Consulting in its review of the AEPwhich included Manitoba Hydro's Bill Assistance initiatives (MKO-Coalition/ MH-I-9). As noted on page 54 of the Dunsky review, "*There is significant coordination between the Affordable Energy Program and Bills Assistance Program"* which includes AEP following up with NHN participants for participation, mandatory application to AEP of NHN grant recipients, the use of customer billing data to target customers in arrears and those with high consumption and the integration between Credit and Recovery for customer referrals to AEP.

Manitoba Hydro would also like to ensure that the record is clarified with regard to AEP eligibility. Mr. Colton is incorrect in his evidence when referring to the Affordable Energy Program on page 107 when he stated, "The Manitoba Hydro EE program is limited to homeowners." As noted in Manitoba Hydro's response to MMF/MH I-41 and as noted in the Dunsky review, the AEP targets both homeowners and tenants.

7.2. Manitoba Hydro's Payment Performance Has Been Improving

On pages 20-22, Mr. Colton presents a variety of statistics related to Manitoba Hydro's payment experience and concludes, *"In short, Manitoba Hydro is experiencing a significant and continuing deterioration in payment performance."*

However, Mr. Colton fails to take into consideration that in comparing 2014 to 2012 he is comparing a year with above normal temperatures to one with below normal temperatures. Below normal temperatures lead to higher energy consumption, which in turn leads to higher than normal customer bills and higher revenue for Manitoba Hydro. The 2014 statistics are further impacted by the fact that the eight-month period of October 2013 to May 2014 consisted of persistent below normal temperatures, which would have tended to result in consecutive above normal bills for energy consumers. Figure 11 provides the Heating Degree Days ("HDD") by month for each 2012, 2013 and 2014, the percentage change from the previous year and the "normal" HDD calculated for 2014. Figure 12 provides the average residential bill by month for 2012-2014.

Figure 11. Heating Degree Days by Month 2012-2014

Heating Degree Days (DDH) by Month with Percentage Change from Previous Year						
	2014		**2013**		**2012**	**2014 Normal**
	DDH	% Change	DDH	% Change	DDH	DDH
January	1,033.5	8.66%	951.1	23.87%	767.8	947.9
February	949.4	21.45%	781.7	11.85%	698.9	787.2
March	825.9	7.15%	770.8	107.59%	371.3	627.9
April	411.1	-14.78%	482.4	97.46%	244.3	303.0
May	134.8	15.91%	116.3	40.63%	82.7	122.4
June	4.6	-65.67%	13.4	35.35%	9.9	18.4
July	2.7	68.75%	1.6	-	.0	1.5
August	3.3	200.00%	1.1	-	.0	4.7
September	63.6	97.52%	32.2	-63.86%	89.1	69.4
October	226.6	-22.93%	294.0	-5.44%	310.9	276.2
November	684.2	15.57%	592.0	-1.51%	601.1	556.0
December	743.7	-31.03%	1,078.3	21.21%	889.6	855.3
Annual	5,083.4	-0.62%	5,114.9	25.81%	4,065.6	4,569.8

Figure 12. Average Residential Bill

(i) Residential - Average Bill			
	2014	*2013*	*2012*
January	$164.14	$145.40	$123.96
February	$153.49	$143.20	$119.33
March	$138.73	$118.61	$104.62
April	$128.21	$122.19	$93.86
May	$93.06	$83.63	$72.05
June	$72.87	$66.94	$63.62
July	$70.93	$72.13	$73.63
August	$78.82	$67.92	$70.44
September	$66.50	$75.48	$65.31
October	$81.37	$75.60	$76.66
November	$99.16	$99.41	$96.73
December	$131.45	$129.96	$117.24
Average	$106.56	$100.04	$89.79
% increase	6.52%	11.42%	

Mr. Colton argues that the total dollars of residential arrears increased dramatically and is evidence of deteriorating payment performance. Manitoba Hydro submits this is evidence that arrears increase when revenue increases.

This same error in analysis occurs at page 23 where he compares late payment charges for the 2012-2014 period. While Mr. Colton's correctly summarizes that the average monthly number of accounts to which late payment charges are applied increased from roughly 77,000 in 2012 to roughly 84,000 in 2014, he once again fails to take into account the impact that colder weather would have had on customer bills. Looking at the number of accounts to which late payment charges were applied as filed in the previous two GRA filings, it is clear that the experience of the last three years does not represent a pattern of deterioration, but rather one of variation.

Figure 13. Percentage of Residential Customers Billed Late Payment Charges

Year	Monthly Average # of Residential Customers Billed Late Payment Charges	Total # of Residential Customers	% of Residential Customers Billed Late Payment Charges
2007	83,672	450,823	18.6%
2008	81,686	455,430	17.9%
2009	84,096	460,804	18.2%
2010	79,633	465,055	17.1%
2011	80,212	469,635	17.1%
2012	76,779	474,661	16.2%
2013	81,844	480,254	17.0%
2014	83,767	486,654	17.2%

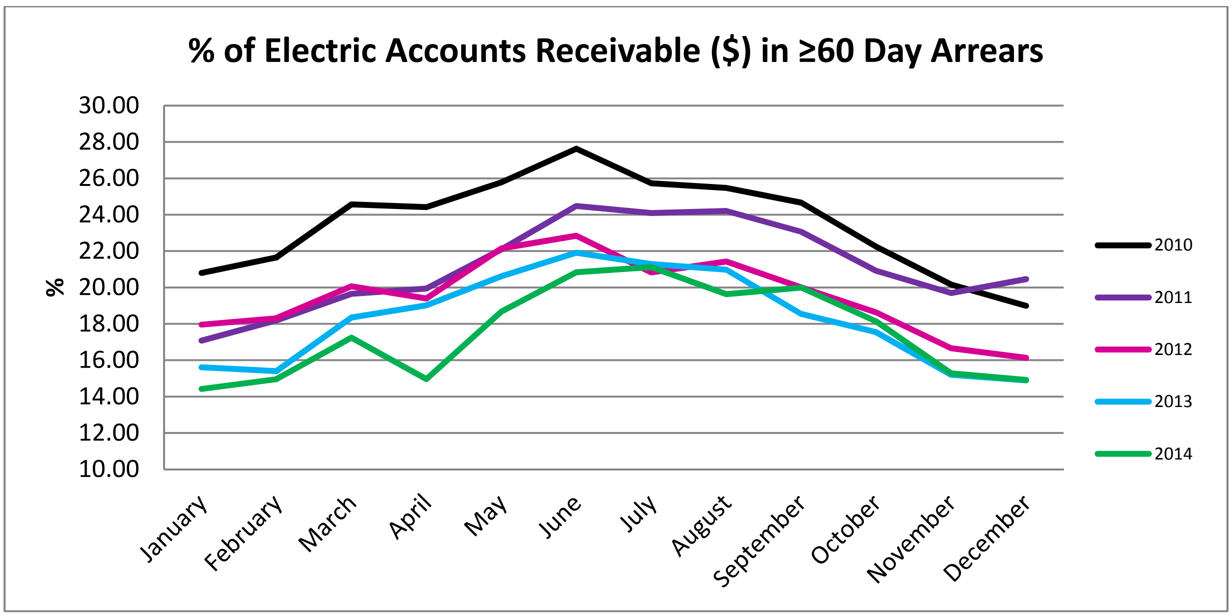
It should also be noted that the years 2011 and 2012 were lower than would have normally been the case because Manitoba Hydro chose to cancel the billing of late payment charges for customers who were affected by flooding in the spring of 2011 during the period of April 2011 to May 2012.

7.3 Manitoba Hydro Sets Appropriate Standards for Managing Customer Payment

Mr. Colton contends (page 22) that Manitoba Hydro has failed to respond to a deterioration in residential payment performance: *"One attribute of reasonable and prudent management is not simply to measure the outcomes of your internal processes, but also to adapt those processes when performance falls short. Even though Manitoba Hydro falls woefully short in this management process from the very beginning, in failing to even establish performance standards, as I describe below, the Company also engages in unreasonable action by failing* *to respond to its deterioration in residential payment performance by adapting its processes."*

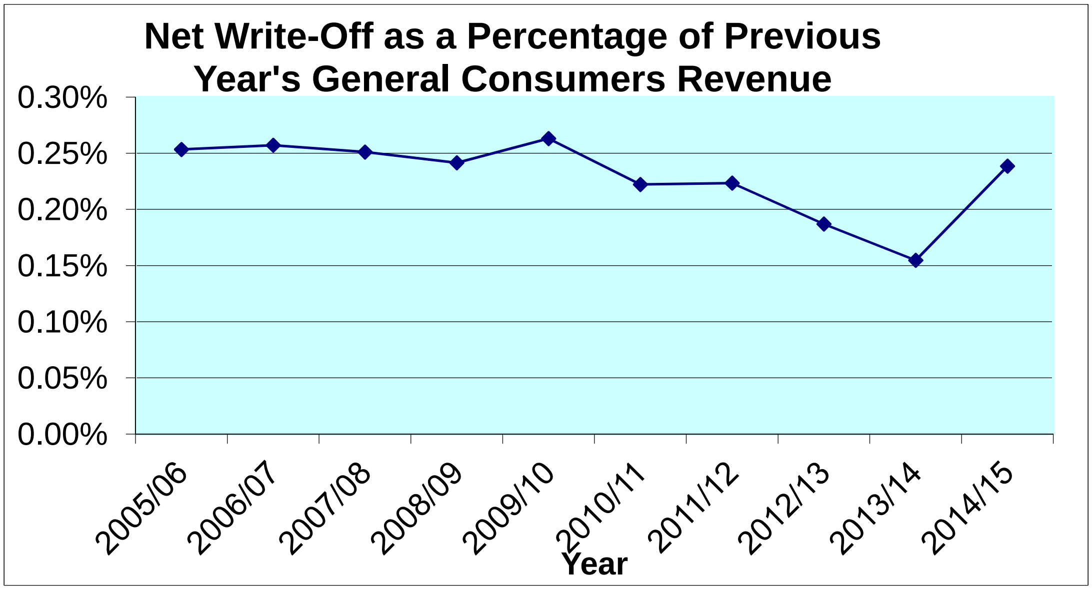
Mr. Colton is incorrect on both main points he makes in this statement. Manitoba Hydro does measure the outcomes of its Credit and Recovery activities, it just uses different measures of performance than the ones selected by Mr. Colton. One measure used by Manitoba Hydro is the % of Electric Accounts in 60 day or more arrears. On this measure, Manitoba Hydro's Credit and Recovery performance has shown consistent improvement over the past five years as presented in the Figure below.

Figure 14. Percentage of Electric Accounts in 60 Days or More Arrears



Another key financial measure of Credit and Recovery performance is the annual write-off of bad debt. In order to take into account fluctuations in weather and overall revenue can have on bad debt, Manitoba Hydro uses a measure that compares the net write off in the current year and compares it to the previous year's General Consumers Revenue (the year in which the energy would have been consumed that is associated with the dollars being written off). The Figure below shows Manitoba Hydro's performance on this measure over the past ten years.

Figure 15. Net Write-Off as a Percentage of Previous Year's General Consumers Revenue



Manitoba Hydro also tracks various measures related to Credit and Recovery activities, such as the number and value of payment arrangements created and completed. Performance around these measures is presented below.

Figure 16. Number of Payment Arrangements by Month

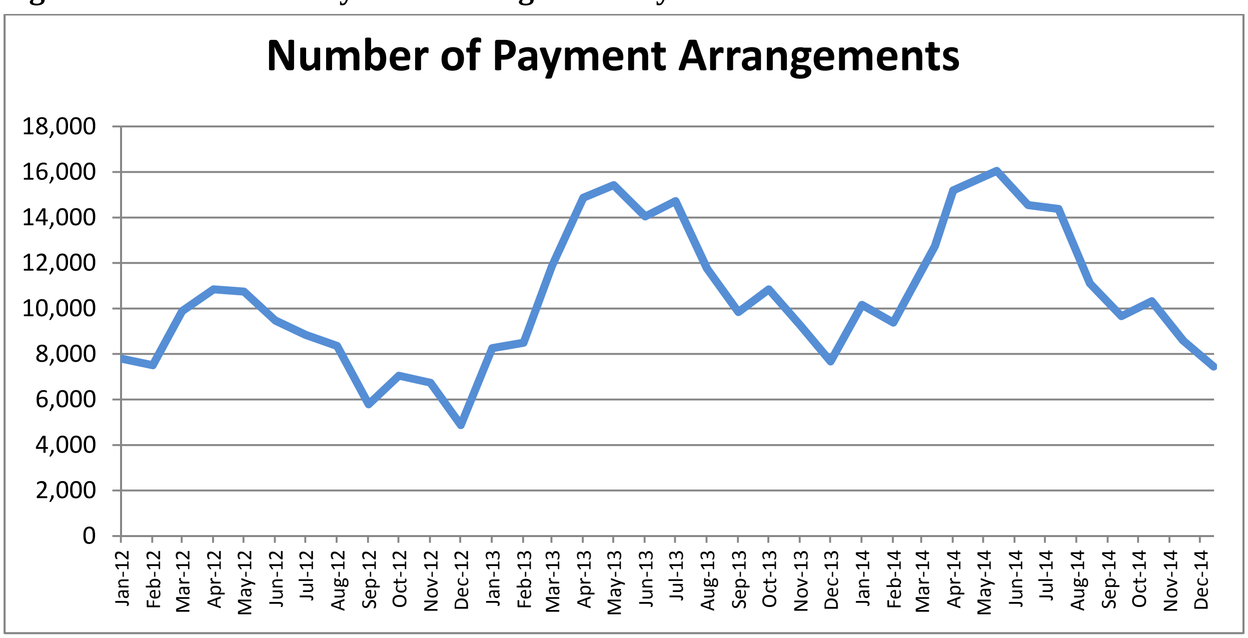


Figure 17. Payment Arrangements Completed

Payment Arrangements			
	2014	**2013**	**2012**
# of Arrangements	139 571	137 101	98 485
Value of Arrangements	114.10M	106.39M	60.72M
Value of Accounts Where Payment Arrangements Are Completed	33.75M	28.58M	18.6M

On page 32 of his testimony, Mr. Colton concludes, *"…the failure to address inability-to-pay imposes a working capital expense on all customers. According to Manitoba Hydro, the Company's average monthly electric accounts receivable increased by more than 25% from 2012 to 2014, from $104.757 million to $131.413 million. (GAC/MH-I-2(c)). This increase in receivables will generate a resulting increase in working capital, whether or not the Company actually resorts to borrowing. Even in the absence of borrowing, the increase in receivables will reduce available cash to the Company and result in an opportunity cost to Manitoba Hydro."*

While in theory, Mr. Colton's conclusion that an increase of $26.7 million in average accounts receivable will impact the company's working capital requirements is correct, he once again fails to recognize the impact of the variability of weather on Manitoba Hydro's operations. This increase in accounts receivable was largely driven by an increase in General Consumers Revenue of 17% or $206.4 million annually over this same period. Therefore, during this period, Manitoba Hydro had greater available cash than would have been anticipated. As can be observed in the following Figure, past due receivables as a percentage of all receivables stayed relatively constant (declined slightly) over the 2012-2014 period.

Figure 18. Past Due Accounts Receivables

Month	2014 Total AR	2014 Past Due AR	2014 % of AR Past Due	2013 Total AR	2013 Past Due AR	2013 % of AR Past Due	2012 Total AR	2012 Past Due AR	2012 % of AR Past Due
January	$142,621	$28,886	20%	$135,282	$28,064	21%	$118,039	$29,528	25%
February	$163,176	$35,387	22%	$156,206	$33,252	21%	$124,323	$31,892	26%
March	$165,294	$38,050	23%	$151,121	$37,207	25%	$117,471	$31,158	27%
April	$164,519	$36,993	22%	$152,221	$34,369	23%	$119,691	$31,731	27%
May	$150,986	$34,971	23%	$133,529	$33,295	25%	$101,578	$30,064	30%
June	$129,983	$33,069	25%	$122,685	$31,818	26%	$92,088	$26,955	29%
July	$117,535	$29,025	25%	$114,717	$27,972	24%	$96,905	$25,094	26%
August	$116,982	$27,628	24%	$102,754	$25,913	25%	$87,611	$24,088	27%
September	$101,112	$25,978	26%	$104,419	$24,256	23%	$92,699	$23,378	25%
October	$94,280	$22,733	24%	$92,685	$22,054	24%	$91,991	$22,083	24%
November	$110,320	$23,893	22%	$106,715	$22,969	22%	$99,823	$22,162	22%
December	$120,144	$26,033	22%	$123,900	$26,513	21%	$114,863	$26,518	23%
Average	**131,413**	**$30,220**	**23%**	**124,686**	**$28,974**	**23%**	**104,757**	**$27,054**	**26%**

At page 117, Mr. Colton states: *"Throughout my testimony, I have demonstrated that what Manitoba Hydro is doing today is not cost-effective because the Company is expending effort and getting poor payment results (because it is not addressing the underlying problem of inability-to-pay). That's objectionable."*

As has been demonstrated above, Mr. Colton's evidence of poor payment results relies on comparing results of a relatively warm year to those of a relatively cold year. By a number of measures, Manitoba Hydro has presented evidence that its payment performance has actually been improving.

Manitoba Hydro has taken and continues to take steps aimed at improving the cost-effectiveness of its credit and collection activities. In March 2013, Manitoba Hydro made significant changes to the organization of its credit and collection functions. Prior to March 2013, Credit Representatives based in the Credit and Recovery Services Department in Winnipeg were responsible for collection actions on final bills that had not been paid after 90 days for the entire province, as well as active accounts in arrears within the Winnipeg region. Collection activities for active and recently closed accounts located outside of Winnipeg were handled by administrative staff in the various district offices and customer service centres located throughout the province. As part of Manitoba Hydro's District Consolidation Project, all credit related activities (other than field disconnections and reconnections) were centralized to the Credit and Recovery Services Department in Winnipeg. This re-organization has allowed for a consistent treatment of accounts province wide as district administrative staff often had competing priorities to address given the nature of their other responsibilities.

In order to improve the cost effectiveness of the workload being transferred to Credit and Recovery Services, Manitoba Hydro undertook an Information Technology project to help focus resources on customers in need of the most attention. The Predictive Analytics project, which was implemented in mid-2014, measures past payment history to assess potential future payment performance. The project included the acquisition of an auto dialer and analytics and reporting capabilities used to target customers who need to be contacted and to present Credit Representatives with more comprehensive and useable information regarding the account of the customer with whom they are dealing. These projects, and other changes associated with these projects contributed to the decline in Credit and Collection Costs as provided in Manitoba Hydro's response to MKO-COALITION/MH-I-2(d).

7.4 Manitoba Hydro's Legislative Context and the Policy Decision of Whether to Offer a Rate Affordability Program

Manitoba Hydro views the adoption and implementation of a Low Income Affordability Program, specifically the type of program proposed by Mr. Colton whereby rates for certain customers are subsidized based on the income of the customers to be outside of Manitoba Hydro's mandate as it is defined by its enabling legislation.

Manitoba Hydro's mandate flows from section 2 of *The Manitoba Hydro Act*, C.C.S.M. H190. Section 2 provides that:

> *The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and , in addition, are*
>
> *(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and*
>
> *(b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.*

Manitoba Hydro's mandate does not extend to issues associated with the affordability of electricity as proposed by Dr. Colton. *The Manitoba Hydro Act* provides clear context that the Corporation's mandate to promote economy refers to the production and provision of electricity to customers at a cost reflective of least cost planning considerations and to promote efficiency refers to efficiency in the end-use of power (such as Manitoba Hydro's Lower Income Energy Efficiency Program).

The Manitoba Hydro Act stipulates in section 39(1) that "The prices payable for power supplied by the corporation <u>shall</u> be such as to return to it in full the cost to the corporation, of supplying the power, including" operating expenses, interest and debt service costs, working capital, and reserves.

In section 39(2.1), *The Manitoba Hydro Act* states that "The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province". Thus, Manitoba Hydro has a clear obligation to fully recover its costs to supply power and in doing so, it must charge equalized rates to each class of customers.

The *Manitoba Hydro Act* also prohibits the funds of the Corporation being employed for the purposes of the government or any agency of the government in section 43(3). This section places limits on the use of Manitoba Hydro's funds and marks a delineation with respect to the use of funds for intended and legitimate purposes as set out in Manitoba Hydro's mandate as set forth above and other social policy purposes which are within the purview and jurisdiction of the legislature.

In response to PUB/GAC-14, GAC provides its understanding of the PUB's jurisdiction over Manitoba Hydro in support of the assertions made that the PUB should decide the threshold policy issue of implementation of an affordability program, facilitate a collaborative process and decide disputed areas of program design based on a collaboration process final report.

GAC submits that pursuant to the Ontario case of *Advocacy Centre for Tenants-Ontario v Ontario (Energy Board)*, 2008 O.J. #1970 (the "Advocacy Centre case") and the factors to be considered by the PUB pursuant to section 26(4) of *The Crown Corporations Public Review and Accountability Act* (the "Accountability Act"), the PUB has the jurisdiction to consider the proposal put forward by GAC with respect to a rate affordability program. GAC also relies upon section 27 and 28 of *The Public Utilities Board Act* (the "PUB Act") in support of their assertion that the PUB has jurisdiction to require and to facilitate a collaborative process, and on sections 27, 28 and 31 of the PUB Act as providing the PUB with the jurisdiction to decide the disputed areas.

While GAC referenced the Ontario decision in its response to GAC/PUB 14, it must be noted that this issue was also considered in Nova Scotia, by the Nova Scotia Court of Appeal. In Dalhousie *Legal Aid Service v. Nova Scotia Power Inc*.[7], the issue before the court was whether or not the Utility and Review Board had committed a reviewable error by concluding that it had no statutory authority to adopt a rate assistance program for low income customers.

The Nova Scotia Utility and Review Board in concluding that it had no power to consider the proposed Rate Assistance Program stated:

> The Board has the authority given to it by the Legislature to perform its duties in accordance with the provisions of the Act. The Board's role is to make decisions, based on fact and law, within the parameters of the statutory authority it has been given by the Legislature. The Board's duty is to follow public policy decisions made by the Legislature and expressed in statutes. The Board does not have jurisdiction to establish public policy. That is the role of elected officials who are accountable to the public for this function. It seems almost certain that the RAP, as described by Mr. Colton, would result in the electricity bills of certain customers, depending on their income, being subsidized by other customers. In the Board's view, this is a social and public policy question which falls within the purview of the Legislature rather than the Board.[8]

In its reasons, the Nova Scotia Court of Appeal clarified that "[t]he Board's regulatory power is a proxy for competition, not an instrument of social policy".[9] The court also confirmed that "[i]t is for the Legislature to decide whether to expand the Board's purview" to authorize different residential rates based on income.[10] The Supreme Court of Canada denied leave to appeal.[11]

Similarly, the mandatory requirement in *The Manitoba Hydro Act* that rates charged for power supplied to a class of grid customers within the province be the same throughout the province, precludes the implementation of a rate assistance plan for low income residential customers. An order by the Board for different rates for low income residential customers and other

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[7] Dalhousie Legal Aid Service v. Nova Scotia Power Inc. 2006 NSCA 74.
[8] *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* 2006 NSCA 74 at para 8.
[9] *Ibid* at para 33.
[10] *Ibid* at para 25.
[11] *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* 364 N.R. 391(note).

residential customers on the grid would contravene section 39(2.1) of The *Manitoba Hydro Act*.

GACs position, also ignores section 2(5) of the PUB Act which clearly states that

> Subject to Part IV of *The Crown Corporations Public Review and Accountability Act* and except for the purposes of conducting a public hearing in respect of an application made to the board under subsection 38(2) or 50(4) of *The Manitoba Hydro Act*, this Act, other than subsection 83(4) and the regulations under that subsection, does not apply to Manitoba Hydro and the board has no jurisdiction or authority over Manitoba Hydro.

It is clear that other than the authority granted to the PUB to review Manitoba Hydro's rates for service and sections 38(2), 50(4) and 83(4), the other sections, including sections 20, 27, 28 and 31 of the *PUB Act* do not apply to Manitoba Hydro.

Mr. Colton indicates at page 88 of his Pre-Filed Evidence that the Ontario Minister of Energy decision to implement the Ontario Electricity Support Program was based on a report of the Ontario Energy Board. The Ontario Energy Board issued the report as a result of a specific request from the Ontario Minister of Energy in April 2014[12] that the Ontario Energy Board prepare a report regarding the development of a program designed to protect low-income residential electricity consumers. To this end, the Ontario Minister of Energy invoked his power under s. 35 of the *Ontario Energy Board Act*, which states that "The Minister may require the Board to examine, report and advise on any question respecting energy." The result of this request was the report published in December 2014.

It should be noted that the report issued by the Ontario Energy Board also indicated that the Board believed legislative change would be necessary as the Ontario Energy Board indicated that they did not have the authority to set a provincial charge for this type of program and also establish the rules for the funds to be disbursed to the distributors.[13]

One of the items included in the Ontario Energy Board's report was a study gauging ratepayer support for the broad objectives of the program and to help align program design with the values and expectations of ratepayers[14]. The Ontario Energy Board interpreted the results of the survey to mean that Ontario ratepayers would support targeted assistance to low-income

[12] Ontario Energy Board - Report of the Board: Developing an Ontario Electricity Support Program (December 22, 2014) - Appendix "A"
[13] Ontario Energy Board - Report of the Board: Developing an Ontario Electricity Support Program (December 22, 2014), pages. 25-26
[14] Ontario Energy Board - Report of the Board: Developing an Ontario Electricity Support Program (December 22, 2014), page. 6

customers with the greatest need and that taxes are the preferred funding option but Ontario ratepayers would be satisfied with a modest provincial charge on their energy bills.

Manitoba Hydro views the issues in Manitoba as being very similar to those in Ontario and that the steps taken in Ontario (i.e. a direction from the Minister, a survey gauging ratepayer support and legislative amendments) would also have to be implemented in Manitoba prior to any implementation of a specific bill affordability program.

APPENDIX A. REBUTTAL EVIDENCE OF GANNET FLEMING

MANITOBA HYDRO

IN THE MATTER OF MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

REBUTTAL EVIDENCE

OF

LARRY E KENNEDY

MAY 20, 2015

Gannett Fleming

Excellence Delivered ***As Promised***

Depreciation Rebuttal

LARRY KENNEDY

Introduction and Overview

Q1. Please state your name and business address

A1. My name is Larry Kennedy and my business address is Suite 277, 200 Rivercrest Drive S.E., Calgary, Alberta, T2C 2X5.

Q2. Please state your occupation.

A2. I am Vice President of Gannett Fleming Canada ULC, a wholly-owned subsidiary company of Gannett Fleming Inc.

Q3. Have you previously testified before this or any other regulatory boards?

A3. Yes, I have testified on numerous occasions before regulatory boards throughout Canada as summarized in my Curriculum Vitae attached to this evidence. Also, as summarized in my Curriculum Vitae, I have prepared a number of additional depreciation reviews that have resulted in negotiated settlements or where appearances were not required.

Of specific note, I testified as an expert witness on depreciation-related matters on behalf of Manitoba Hydro before the Manitoba Public Utilities Board ("the PUB") as part its 2012/13 & 2013/14 General Rate Application. Additionally, Gannett Fleming Inc. prepared the 2000, 2005 and 2010 depreciation studies for Manitoba Hydro.

Q4. Please state the purpose of this rebuttal evidence.

A4. In preparation of the Manitoba Hydro 2015/16 & 2016/17 General Rate Application, I prepared a full depreciation study (the "Gannett Fleming Study") which was filed in Appendix 5.6 of Manitoba Hydro's General Rate Application ("GRA"). This rebuttal evidence responds to the evidence that has been submitted into this proceeding by Mr. Patrick Bowman on behalf of the Manitoba

Industrial Power Users Group (“MIPUG”) and Ms. Patricia Lee on behalf of MIPUG and “The Coalition” in this proceeding concerning depreciation related matters.

Q5. Please provide the context for your response to the evidence filed in this proceeding.

A5. In this current Manitoba Hydro General Tariff Application, the Company filed a Depreciation Study performed by Gannett Fleming Canada ULC. The Study presented depreciation rates and accruals based on plant balances and service life data through the year end March 31, 2014. Additionally Gannett Fleming completed an analysis in compliance with the PUB directives #8 and #9 from Order No. 43/13 of the PUB. The Gannett Fleming report summarizing the results of the analysis has been entered into this proceeding as Appendix 11.49 of the General Rate Application.

MIPUG and the Coalition have retained their own depreciation witnesses, Ms. Lee and Mr. Bowman. Neither Ms. Lee nor Mr. Bowman has provided any comment on the average service life estimates contained in the Gannett Fleming depreciation study. However, both Ms. Lee and Mr. Bowman have provided comments on the Gannett Fleming recommendation to incorporate the use of the Equal Life Group (“ELG”) procedure in the calculation of the depreciation rates for rate setting purposes related to Manitoba Hydro’s transition to the IFRS. Additionally Mr. Bowman is also recommending the exclusion of a provision for the recovery of future costs of removal (“net negative salvage”).

This rebuttal evidence will demonstrate the following:

- The Manitoba Hydro data bases are maintained in sufficient detail by original installation year to rely upon for the use of the ELG procedure;
- Sufficient retirement history exists for the use of the ELG procedure;
- The ELG procedure is no more sensitive to the Iowa curve shape than the ASL Procedure;
- The Manitoba Hydro accumulated depreciation account is maintained at a level that is consistent with prior approved levels by Canadian regulatory authorities that have granted approval for use of the ELG procedure for rate setting purposes;
- The recovery of differences in the calculated and booked accumulated depreciation amounts over the composite remaining life of each account is appropriate; and

- There is no need to implement any type of phase in period for use of the ELG procedure or to implement the ELG procedure to new asset additions only.

Additionally, the rebuttal evidence will explain that while the inclusion of recovery of costs of removal ("net negative salvage") in depreciation rates for rate setting purposes is appropriate and widely accepted, Manitoba Hydro implemented a policy decision to exclude it to manage the implementation of the ELG procedure.

Alleged short comings in the historic retirement data sets

Q6. What are the shortcomings in the retirement datasets alleged by Ms. Lee?

A6. Ms. Lee made the following generalized claims:

- "Hydro's 2005 depreciation study implies that historic data is a mix of aged and unaged data. However there is no mention of this in the 2014 depreciation study. In fact, the 2014 depreciation study almost implies that all of the data is aged. Un aged data does not become aged without some synthesization intervention "[1];
- "It is clear that for many of the Hydro's accounts there has been insufficient retirement activity from which to derive a future pattern."[2]
- While MH may claim that it does actuarial data for its generation assets, the data was the result of statistical aging as part of the 2005 depreciation study. In other words, aged data has been simulated.[3]

Q7. Please provide comment on the generalized claims of Ms. Lee regarding the retirement data bases.

A7. As noted by Ms. Lee, the 2014 depreciation study is silent on the need to age retirement data. However, the absence of discussion on the need to age any retirement data is because in the period from 2005 through to 2014, Manitoba Hydro has undertaken a significant effort to determine the actual installation vintages of the historic retirement activity. This effort included

[1] Pre-filed Testimony of P. Lee, dated April 24, 2015, page 10, lines 24 through 27.
[2] Depreciation Evidence of the Office of the Utilities Consumer Advocate, page 36, Question and Answer 73.
[3] PUB/MIPUG/COALITION (LEE)-5(a).

the retrieval of the original historic retirement information for the accounts that included unaged data and a review of the retirement information to determine the actual installation vintage for historic retirement transactions. This large effort to determine the actual vintage information for historic retirement transactions is in contrast to the assumption made by Ms. Lee that the vintage information was determined through a statistical aging process. In 375 out of 385 accounts comprising over 86% of the total plant studied, actual retirement data by installation vintage was available for analysis. Ms. Lee's claim that the lack of actual vintage information on historic retirement transactions is cause to reject the conversion to the ELG procedure is not accurate.

Ms. Lee's conclusion that some accounts do not contain enough retirement information to use as a basis for the determination of a future retirement pattern would largely only be applicable to some generation accounts. However, the development of an estimated future retirement pattern is not predicated solely on the review of historic information. In fact, the retirement rate analysis is only one of a number of relevant factors that is considered in the average service life estimation phase of a depreciation study. Gannett Fleming has had a long history in the completion of depreciation studies for Manitoba Hydro and has had the opportunity to visit and take site tours of many of the company's generation facilities. Additionally, Gannett Fleming has completed studies on many of the Canadian hydraulic generation plants and has developed a strong understanding of the retirement characteristics of Canadian hydro facilities. Gannett Fleming also completed a significant amount of interviewing and discussions with Manitoba Hydro engineering and operating staff and management through this and prior assignments. Based on the historic records and this additional information, Gannett Fleming determined the retirement dispersion curve shape. The assumption that the estimation of a future retirement curve can only be made on the basis of historic retirement information, ignores other important considerations such as the significant knowledge and information available from the internal Manitoba Hydro resources and the background of the Canadian hydro generation industry. In fact, Gannett Fleming notes that simple reliance on only historic retirement information can lead to the selection of inappropriate results for the estimation of the future retirement patterns, keeping in mind that the goal of the life analysis is to select survivor curves that best represent the expectation of future retirement patterns.

Notwithstanding the above comments, Gannett Fleming notes that a review of the retirement dispersion curves recommended in the Gannett Fleming study has indicated that in accounts where there is limited retirement activity, high-moded curves have been selected (predominantly R3 and R4 curves, with some R5 and S3 curves), in part to reflect the absence of significant retirement activity to date. These high-moded curves prescribe very minimal early retirement activity. As such, the concerns expressed by Ms. Lee that the ELG will place too much weighting on shorter lived interim retirements is not applicable. Additionally, it is noted that neither Ms. Lee or Mr. Bowman has made any comment or recommended any changes to the Iowa curve selections made by Gannett Fleming. If it is the position of Ms. Lee that the Iowa curves selected by Gannett Fleming do not reflect the future retirement pattern of any account that evidence to support such a position is absent. In summary, there is no evidence to suggest that the future retirement patterns as recommended by Gannett Fleming are not reasonable.

Q.8 Ms. Lee indicates that the ELG Procedure is more sensitive to curve shape than is the ASL procedure.[4] Is this claim accurate?

A8. On page 11 of Ms. Lee's testimony she states, *"Because of the nature of the ELG formula, it is more sensitive to errors in projected lives and/or mortality dispersions (retirement patterns). To the extent a category has had miniscule retirements, fitting an appropriate Iowa curve becomes very subjective."*

Gannett Fleming contends that Ms. Lee's concern about the sensitivity of the ELG formula to errors in projected lives is overstated and that such concern is also applicable to calculations prepared under the ASL method. Depreciation is by nature, an exercise in forecasting the future and the difficulties involved in any forecast of the future are inherent in either the ASL or ELG procedure. In fact, both the ELG and ASL procedures depend on the exact same forecasts of future retirement dispersion and Iowa curves. Since both procedures use the same Iowa curves to forecast life characteristics, both procedures make the same assumption of precision in estimate and just as the ELG calculations are sensitive to the dispersion represented by the Iowa curve, so

[4] For example, Pre-filed Testimony of P. Lee, dated April 24, 2015, page 12, lines 1 through 31.

are the ASL calculations. As an example, for a group of property at an age of 20 years, the average remaining life based on a 40-R4 survivor curve is 20.48 years. If instead, the 40-R1 curve is used, the average remaining life for the same group of property is 26.11 years, a 27% increase.

The following is a further example to demonstrate this point. Consider a utility account in which the actual retirements occur in accordance with the 40-R2 survivor curve. To model the error inherent in both the ELG and ASL calculation procedures, consider the following three scenarios:

1. The correct 40-R2 survivor curve is used;
2. A 35-R2 survivor curve is used until 2010, at which point the estimate is corrected to the 40-R2 survivor curve; and
3. A 45-R2 survivor curve is used until 2010, at which point the estimate is corrected to the 40-R2 survivor curve.

This example will model a scenario in which the estimate is correct and also scenarios in which too high and too low estimates have been used. Based on this model, the error inherent in each procedure for scenarios 2 and 3 can be calculated as the difference between the depreciation rates in these scenarios and the depreciation rates for scenario 1. This example will show the impact of both increasing and decreasing lives – that is, the forecast errors that occur when the estimate is either too high or too low.

FIGURE 1

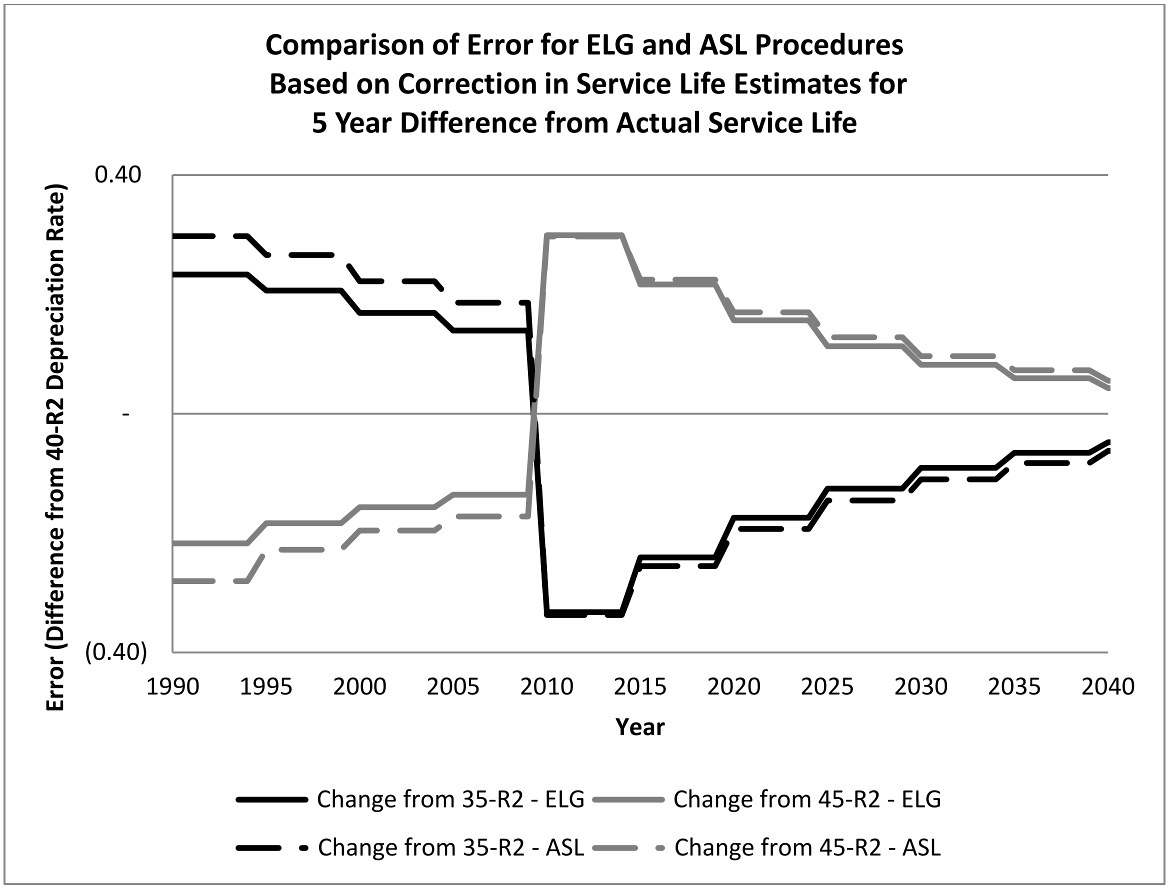
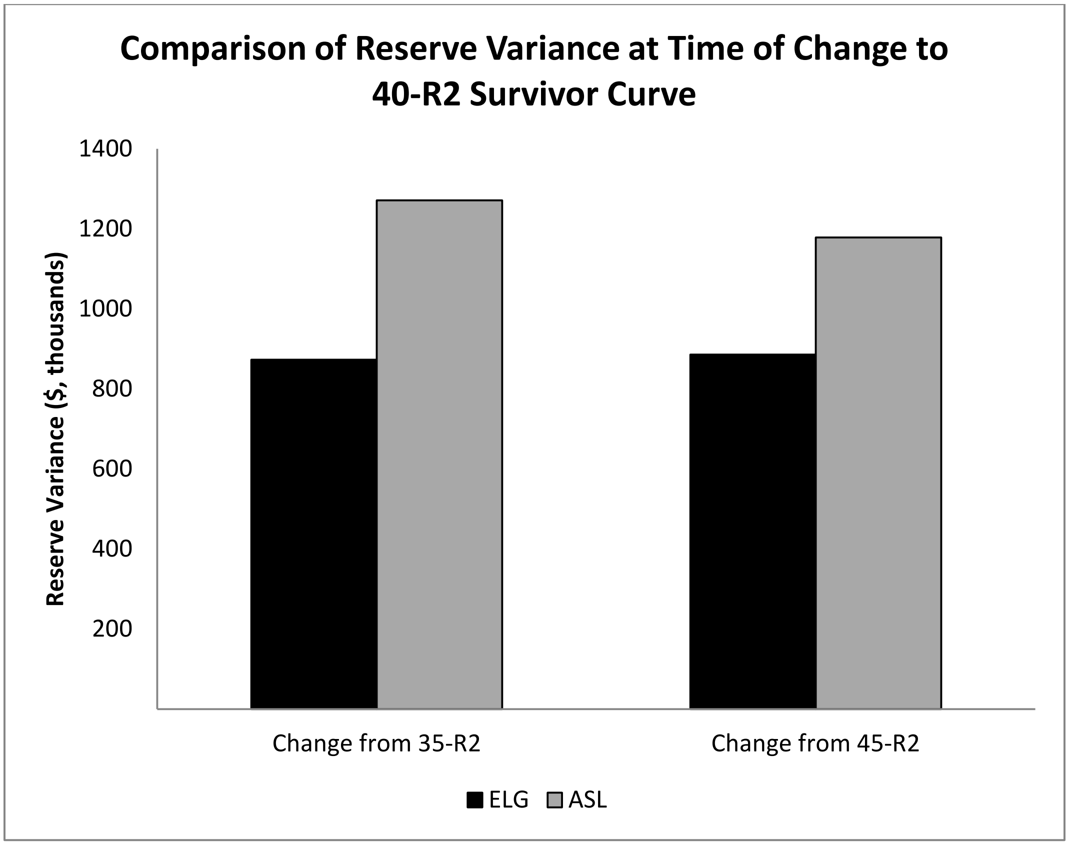


Figure 1 shows the results of this analysis. The solid lines in the chart represent the differences in depreciation rates between scenarios 2 and 3 and scenario 1 for the ELG procedure, and the dashed lines represent the same for the ASL procedure. As the chart shows, at the time of the correction in service life in 2010, the both the ELG and ASL procedures show a similar difference from depreciation rates based on the correct estimate. However, both before and after the change the ASL depreciation rates show a higher degree of error. This analysis indicates there is no basis to conclude that ELG depreciation rates show a higher degree of error.

Another way to assess the error in each procedure is to examine the reserve variance, or differential between the book and theoretical reserve, at the time the service life is adjusted to the 40-R2. As shown in Figure 2 below, the amount of error correction under the ASL procedure is greater than under the ELG procedure.

FIGURE 2



In Figure 1 and Figure 2, the error for the ASL rates is based on a comparison to the ASL rates and theoretical reserve derived from a 40-R2 survivor curve. However, since the property in this example is known to have retirements that occur based on the 40-R2 survivor curve, the ELG rates are the exact same depreciation rates that would be calculated if each unit were depreciated individually over its life. Thus, the correct depreciation rates are the ELG rates based on the 40-R2 survivor curve.

Figure 3

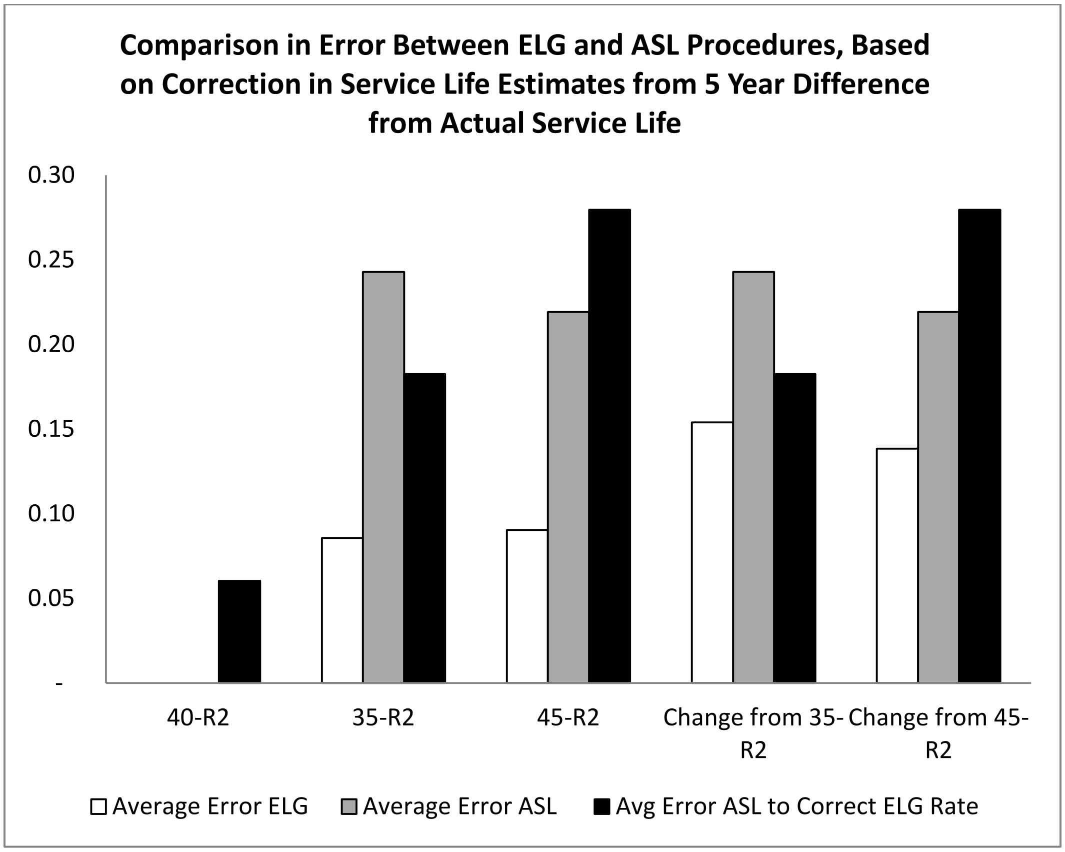


Figure 3 shows the average error for the period 2010 through 2040. This figure includes two additional scenarios, labeled 35-R2 and 45-R2, in which the survivor curve estimate is never corrected. As the figure shows, as compared to the ELG depreciation rates, the error is greater for ASL depreciation rates in every scenario. Thus, an incorrect forecast does not result in greater error for the ELG procedure than the ASL procedure. In fact, in this realistic model the opposite is true. It should also be noted that even when the estimate is correct, the ASL procedure results in error, as shown in the bar labeled 40-R2 in the figure above. This analysis clearly shows that with more real-world situations the ELG procedure does not result in “a greater degree of error” than the ASL procedure. Instead, while both are subject to forecast errors, only ELG will result in the correct depreciation expense when the service life estimate is correct.

Q9. Please describe the issue raised by Ms. Lee that Manitoba Hydro's Accumulated Depreciation account is not maintained at the level necessary for the use of the ELG procedure.

A9. Ms. Lee has indicated in a number of responses to information requests that both plant and reserve detail by vintage is required to maintain the theoretical accuracy of the accumulated depreciation account.[5]

Q10. Please provide comment on the need to maintain the accumulated depreciation account by vintage year

A10. The depreciation study completed by Gannett Fleming was completed on a whole life basis with a test of the accumulated depreciation adequacy which included a true up of any differences between the calculated (or theoretical) accumulated depreciation requirements over the composite remaining life of each account. As indicated in the detailed depreciation calculations included in the Supporting Documents to the Gannett Fleming report, the booked accumulated depreciation balances by vintage do not form any part of the ELG calculations. The actual booked accumulated is only used in the testing of the accumulated depreciation balances to determine the accumulated depreciation true-up requirements as summarized in Tables 2 and 2A (pages IV-14 to IV-23) of the Gannett Fleming report.

In the testing of the booked accumulated depreciation balances to the calculated amounts, the test is to determine if the accumulated depreciation balance as a whole has over or under recovered the depreciation that would reasonably reflect the consumption of the service value of the investment at a given point in time. There is simply no benefit or reason to perform the test at the level as detailed in the evidence of Ms. Lee (i.e. for each installation year). Rather, the true-up is meant to ensure that customers are appropriately paying for the consumption of the service value of the assets from which they are receiving service. In making the test of the accumulated depreciation adequacy at the account level, the information required is as follows:

- The calculated or theoretical accumulated depreciation requirement as of the point in time of the depreciation study;
- The actual booked accumulated depreciation balances as of the point in time of the depreciation study;

[5] For example in PUB/MIPUG/COALITION (LEE)-2.

- A period over which to true-up any variances between the calculated and booked accumulated depreciation variances.

It has already been documented in this rebuttal evidence that sufficient vintage information of additions, retirements and adjustments by installation year are available due to the recent efforts of Manitoba Hydro to retrieve this information. As such, the calculated accumulated depreciation requirement is developed in a manner which recognizes the long established benefits of the ELG procedure. Secondly, the booked accumulated depreciation balances are readily available and known as of the point in time of the depreciation study. As discussed in this rebuttal evidence, this test does not require the determination of the accumulated depreciation balances by vintages. Lastly, when the accumulated depreciation variances are trued-up over the composite remaining life of each account, the determination of the composite remaining life of each account is required. It is important to note that the composite remaining life calculation is an input into the calculation of the accumulated depreciation variance true-up. As such, alternative procedures and methods can be used in the determination of the composite remaining life.

For approximately the past 30 years, the Province of Alberta has been one of North America's largest, if not the most predominate adopter of the use of the ELG procedure for electric and gas utilities, including the large generation facilities (until the de-regulation of the generation function in 1999). The issue of the implementation of the ELG procedure was the subject of much debate in the early 1980's, during which period arguments such as those outlined in the current evidence of Ms. Lee were debated in a number of proceedings. Ultimately, in an Application by TransAlta Utilities in 1982 (which included a very significant investment in large generation plants), the Alberta Energy and Utilities Board (now the Alberta Utilities Commission) strongly endorsed the ELG procedure, but determined that the procedure must be applied on a whole life basis, and any accumulated depreciation variances should be amortized over the composite remaining life of each account. However, the Alberta regulator determined that the composite remaining life calculated using the ELG procedure requires a significant level of vintage information within the accumulated depreciation account, with the resultant calculation being shorter than the physical remaining life of the assets in service. Therefore the Alberta regulator required that the ELG procedure be used for the whole life calculations, but that the Average Service Life ("ASL") procedure be used for the development of the composite remaining life used solely for the purpose of the accumulated depreciation true-up calculations[6]. It was the view of the Alberta regulator that in this manner the better reflection of composite remaining life is achieved.

Mr. Kennedy has reviewed the merits of the AEUB Decision E82131 on a number of occasions and finds the conclusions to be reasonable without compromising the integrity of the whole life ELG calculation that comprises the majority of the depreciation expense. As such, Mr. Kennedy has included the process as established in the 1982 TransAlta Decision in all proceedings, including this current Manitoba Hydro study, where the whole life ELG procedure is recommended, but with the composite remaining life being determined using the ASL procedure for use in the Accumulated Depreciation true-up procedure.

The criticism made by Ms. Lee in her evidence, is more applicable if an ELG remaining life calculation was used. However as indicated above, the recommended ELG procedure applied on a whole life basis was used in the calculation of the Manitoba Hydro depreciation rates. Furthermore, the observations of Ms. Lee that the ELG procedure is often used to reduce the composite remaining life of assets is not applicable in the circumstances of this proceeding as a result of Mr. Kennedy's use of the ASL procedure in the calculation of the composite remaining life that was used as an input into the determination of the amortization period over which the accumulated depreciation variances are calculated.

Q.11 Ms. Lee recommends that if the ELG procedure is approved in this proceeding that it be approved with four conditions as outlined at page 12 of her evidence. Please provide comment.

A11. Ms. Lee recommends that if the ELG procedure is approved in this proceeding that the following four conditions be adopted as follows:

- Adopt ELG for new additions only;
- Adopt a 3-year phase in approach;

[6] Decision E82131 of the Public Utilities Board of Alberta, dated June 21, 1982 in the matter of an application by TransAlta Utilities Corporation.

- Require Manitoba Hydro to maintain the requisite data for each vintage to which an ELG rate is applied as well as vintage reserve data; and
- Require a depreciation study at least once every three years to monitor the status and to address any needed adjustments.

The recommendation of Ms. Lee to implement the ELG procedure on new additions only is flawed in two ways. Firstly, the recommendation is largely based on the premise that Manitoba Hydro does not have its current aged balances or historic retirement activity on a vintage basis. As indicated in prior sections of this rebuttal evidence, this premise is not factual. In fact Manitoba Hydro has developed its retirement data bases and aged balances using actual historic retirement information. Secondly, this recommendation will not provide for compliance with the International Financial Reporting Standards ("IFRS"), as all investment made prior to March 31, 2014 would not be componentized at the required level to apply ASL in accordance with the requirement of the IFRS.

The implementation of the use of the ELG procedure through a three-year phase in period is not required. The implementation of the ELG procedure is recommended with an offsetting impact of the removal of the recovery of cost of removal from the depreciation rate calculations. In the view of Mr. Kennedy, implementation of ELG at a time of a second large offsetting recommendation is the optimal timing for such implementation. To introduce a deferral mechanism such as Ms. Lee's recommended 3-year phase in will simply transfer the impact to a future period.

Ms. Lee's recommended condition requiring Manitoba Hydro to maintain vintage plant information is meaningless, as this condition is already being met by Manitoba Hydro. The recommended requirement to keep the accumulated depreciation reserves by vintage is not required. As previously indicated in this rebuttal evidence, this issue was the focus of much debate in regulatory jurisdiction where the ELG procedure is widely accepted and found to not be required. The Alberta regulator has established a process wherein the issues of not keeping the accumulated depreciation reserve by vintage does not compromise the integrity of the ELG calculations. This same process has been followed by Mr. Kennedy in the completion of this study.

With regard to Ms. Lee's recommendation that depreciation studies be completed every three years, Mr. Kennedy notes that Manitoba Hydro has had a history of studies being completed periodically, usually within a three to five-year period. As such, Mr. Kennedy views that this condition is already being met.

Q12 Mr. Bowman suggests that because not all plant will be removed from service net salvage should be removed from the depreciation rate calculations[7]. Do you agree?

A12. Mr. Bowman's assumption is incorrect. Every plant asset will ultimately be retired and/or decommissioned and logically there will be costs to do so, regardless of whether or not the asset is being replaced or returned to a greenfield condition. Mr. Bowman's argument that negative salvage is not required focuses primarily on his assumption that long lived generation assets will simply be replaced and never retired. Salvage costs relating to generation assets make up only $13 million of the $60 million of negative salvage that has historically been included in depreciation rates. The majority of the salvage costs pertain to Substation, Transmission and Distribution assets for which there is no doubt will be subjected to retirement and associated net negative salvage costs.

Q13. Please provide some background on the inclusion of net salvage in depreciation rate calculations.

A13. The inclusion of net salvage percentages is widely accepted in regulatory jurisdictions throughout North America. Depreciation is not simply the allocation of original cost to expense. In the most widely used definition of depreciation for regulated utilities, the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts defines depreciation as "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." The operative words in this definition are "*service value"*. The FERC Uniform System of Accounts goes on to define service value as "the difference between the original cost and the net salvage value of the utility plant". The service value rendered by an asset, i.e. depreciation, must reflect both its original cost and its

[7] Pre-filed Testimony of P. Bowman, dated April 24, 2015, page 26, lines 4 through 18.

net salvage. FERC further defines "net salvage value" to mean the salvage value of property retired less the cost of removal, with "cost of removal" being defined as the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.[8]

Q14. Is recovery of net salvage within depreciation rates common within regulatory jurisdictions throughout Canada?

A14. Yes. Many jurisdictions across Canada recognize the regulatory benefit and fairness to the inclusion of the recovery of the net salvage requirements over the period of time that assets are providing regulatory service. Regulatory decisions allowing the inclusion of net salvage percentages have been rendered by the following Canadian regulatory bodies for rates that are currently in place:

- The British Columbia Utilities Commission;
- The Alberta Utilities Commission;
- The Manitoba Public Utilities Board;
- The Ontario Public Utilities Board;
- The Regie de l'Energie du Quebec;
- The Nova Scotia Utility and Review Board;
- The Newfoundland and Labrador Board of Commissioners of Public Utilities;
- Northwest Territories Public Utilities Board; and
- The National Energy Board of Canada.

[8] All referenced definitions are as per Chapter 1 – Federal Energy Regulatory Commission, Department of Energy, and Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, Definitions Section.

Q15. Has the recovery of costs of removal been considered in decisions addressing Depreciation in other Canadian jurisdictions?

A15. Yes. The issue of recovery of net salvage requirements has received attention in virtually all recent depreciation applications in most jurisdictions across Canada. In particular, the issue was recently reviewed in the following jurisdictions:

- In an application in British Columbia by FortisBC Energy Inc. and separately for FortisBC Inc., the BCUC approved the reinstatement of net negative salvage costs.
- In Alberta, the Office of the Utility Consumers Advocate (the "UCA") and the Consumers Coalition of Alberta (the CCA") have been extremely active in attempting to limit the amount of net salvage costs that are recovered through depreciation. While the UCA and CCA have, on a number of occasions, questioned the level of net salvage percentages, neither party disputes the concept of recovery of net negative salvage. As such, the issue of net salvage in Alberta generally is an issue of the amount of recovery, rather than a dispute regarding the recoverability of the estimated costs of removal.
- In Ontario, Enbridge Gas Distribution and Union Gas have both recently filed applications that include very large provisions for the recovery of net salvage. Both applications included a depreciation study that calculated and applied the net salvage estimates in the depreciation rate calculations. The 2011 application by Union Gas did not result in any intervener evidence regarding the inclusion of costs of removal in the revenue requirement and the Ontario Energy Board (OEB) approved a revenue requirement incorporating a cost of removal provision. Enbridge Gas Distribution filed a 2012 depreciation study that also included the recovery of costs of removal in the depreciation rate calculations. The Enbridge study was settled via a negotiated settlement however, the settlement filed with and ultimately approved by the OEB included large provisions for net negative salvage. It is also noted that approval of the recovery of net salvage within depreciation rates has a long standing history before the OEB.
- Utilities in Nova Scotia, New Brunswick, and Newfoundland (Newfoundland Power) have all filed depreciation studies including provisions for net salvage. Generally, in these applications, the concept of the inclusion of the net salvage in the depreciation rates has not been the subject of opposing evidence and has been consistently approved by the regulators in those jurisdictions.

- After a significant amount of evidence, the Yukon Utilities Board declined to allow Yukon Electrical Company Limited ("YECL") to re-instate recovery of net salvage in its depreciation rates in a 2013 hearing.
- The National Energy Board of Canada commissioned a wide sweeping regulatory process - the Land Matter Consultative Initiative (LMCI) to consider the issues of site restoration and net salvage. This LMCI completed after a couple of years with an oral hearing in 2012. The NEB released Decision MH-001-2012, which mandated NEB pipelines to include a recovery of pipeline abandonment costs in the revenue requirements of the company.

Q16. Based on the above, did Gannett Fleming include the recovery of net salvage into the depreciation rate calculations in this study?

A16. The choice to include or exclude the recovery of net salvage into the depreciation rates is a policy decision made by each company. While Ganett Fleming recommends the concept of inclusion of net salvage, Manitoba Hydro implemented a policy decision in 2010 to exclude net negative salvage from the depreciation rate calculations in order to reduce the impact of the implementation of the ELG procedure to customers. Manitoba Hydro has continued this policy decision to this current depreciation study and asked that Gannett Fleming remove the recovery of net salvage from the depreciation rate calculations. As such, the depreciation rates as calculated using the ELG procedure have not included a provision for net salvage. However, it is noted that consistent with the above policy decision, in the submission of depreciation rates calculated in accordance with the ASL procedure, the recovery of net salvage was included.

Q17. Does this conclude your rebuttal evidence?

A17. Yes.

LARRY E. KENNEDY, CDP

TECHNICAL SPECIALTIES

- Public Utility Plant Depreciation
- Public Utility Plant Accounting

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Mr. Kennedy joined Gannett Fleming, Inc. in January 1999 and is a Vice President of Gannett Fleming Canada ULC. His responsibilities include the assembly of data, the preparation and review of depreciation studies, advice to clients regarding asset retirement obligation accounting, plant accounting issues, and provision of general regulatory litigation support.

Representative assignments include:

- **AltaGas Utilities Inc.:** A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board. Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.

- **AltaLink LP:** An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004 additional depreciation studies were filed in 2005, 2010 and 2012. The 2010 and 2012 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards.

LARRY E. KENNEDY, CDP

- **ATCO**: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta Assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities (NWT) Inc. and the distribution assets of Northland Utilities (Yellowknife) Inc. ATCO Electric studies were submitted to the AUC for review, while the Northland Utilities Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to Yukon Public Utilities Board. ATCO Gas studies were prepared in 2010 and were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements.

- **BC Hydro**: This assignment included the development of an average service life study for all of the BC Hydro's electric generation, transmission, distribution and general plant assets. The study, which was prepared for submission to the British Columbia Utilities Commission ("BCUC), included development of depreciation policy for the company, development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, and the compilation of a detailed report. The assignment included the support of the study through the regulatory process. Mr. Kennedy has also completed a review of the cost allocation procedures and practices which was filed with the BCUC in 2010.

- **Centra Gas Manitoba, Inc.:** The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted on issues regarding IFRS compliance and required componentization.

- **Enbridge Gas Distribution Inc.:** Full and Comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- **ENMAX Power Corporation:** Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- **Fortis Inc.:** Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the BCUC in 2005, 2010 and 2011 encompassing both the FortisBC electric and natural gas companies. FortisAlberta studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates.

- **International Financial Reporting Standards (IFRS):** Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association, and to the British Columbia Utilities Commission on this topic.

- **Mackenzie Valley Pipeline Project**: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada.

- **Manitoba Hydro:** A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- **Newfoundland and Labrador Hydro:** Mr. Kennedy developed a comprehensive depreciation study that included the development of depreciation policy and rates for Newfoundland and Labrador Hydro. The study provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 study was the subject of Regulatory Review in 2012.

- **Ontario Power Generation:** Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives the regulated assets were completed in 2011 and 2013, and were submitted to the Ontario Energy Board for review.

- **TransCanada PipeLines Limited – Alberta Facilities:** The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012.

- **TransCanada PipeLines Limited – Mainline Facilities**: The study prepared for submission to the National Energy Board of Canada ("NEB") included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta – Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002, and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011. The 2011 study was fully supported through an appearance before the NEB in 2012

Mr. Kennedy has successfully completed the series of week-long programs offered by Depreciation Programs, Inc. and is a past president of the Society of Depreciation Professionals.

LARRY E. KENNEDY

SUMMARY OF CASES WHERE EVIDENCE WAS PROVIDED BUT APPEARANCES WERE NOT REQUIRED

Year	Client	Applicant	Regulatory Board	Proceeding Number
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Department of Energy	N/A
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric –ISO Issues	Alberta Energy and Utilities Board	N/A
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	The City of Red Deer	The City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation- Transmission	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A

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SUMMARY OF CASES WHERE EVIDENCE WAS PROVIDED BUT APPEARANCES WERE NOT REQUIRED

Year	Client	Applicant	Regulatory Board	Proceeding Number
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCOGas	ATCOGas	Alberta Utilities Commission	1553052
2008	Heritage Gas	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2010	Enbridge Pipelines Limited - Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	FortisAlberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1607159
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A

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SUMMARY OF APPEARANCES BEFORE REGULATORY BOARDS

Year	Client	Applicant	Regulatory Board	Proceeding Number
1999	ENMAX Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2003	AltaLink Management Ltd	AltaLink Management Ltd	Alberta Energy and Utilities Board	1279345
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation- Distribution Assets	Alberta Energy and Utilities Board	1380613
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004

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SUMMARY OF APPEARANCES BEFORE REGULATORY BOARDS

Year	Client	Applicant	Regulatory Board	Proceeding Number
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	Gaz Metro	Gaz Metro	La Regie de L'Energie	R-3752-2011
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink	AltaLink	Alberta Utilities Commission	1606895
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	TransCanada Pipelines Limited	TransCanada PipeLines Limited	National Energy Board of Canada	RH-003-2011
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2013	IntraGaz Incorporated	IntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	Appearance Pending
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Appearance Pending
2015	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Appearance Pending