# Manitoba Hydro 2010/11 & 2011/12 GRA
# Book of Documents (Volume 1) – PUB Counsel

## INDEX



| Tab | Description | Reference |
|---|---|---|
| 1 | Letter of Application | Tab 1- MH Application |
| 2 | IFF09-Actual IFF10 Projected Income Statements | IFF09; IFF10; 59th Annual Report; Q1 & Q2 Fiscal 2011. |
| 3 | 2004-2012 Financial Results and Historical Rate Increases | PUB/MH I-2 (b) Analysis; PUB/MH I -2(b) |
| 4 | IFF09-1 (20 Year Forecast) | PUB/MH I-199 (a) |
| 5 | Load Forecast Information IFF09 Vs. IFF08 | PUB/MH II-194 (a) |
| 6 | IFF09-1 Assumptions | PUB/MH II-45 (a); Analysis of PUB/MH II-193 (b) & (c) |
| 7 | Canadian Gas Association Information | CGA 2010 Supply Bulletins |
| 8 | Foreign Exchange/Export Revenue | PUB/MH I-31 |
| 9 | Export Summary & SEP Data | PUB/MH II-191 |
| 10 | OM&A Cost Per Customer | PUB/MH/PRE-ASK -14 |
| 11 | Historical OM&A | Pre-Ask 15 (a) & (b) |
| 12 | Capitalized OM&A | PUB/MH I-5 (c) Revised; PUB/MH II-2 (b) |
| 13 | Construction Work in Progress | PUB/MH I-19; 59th Annual Report Page 81; PUB/MH I-204 Revised |
| 14 | IFRS Impacts IFF08 -1 Vs. IFF09-1 | PUB/MH II-150 (c) |

# Manitoba Hydro 2010/11 & 2011/12 GRA
# Book of Documents (Volume 1) – PUB Counsel

## INDEX



| Tab | Description | Reference |
|---|---|---|
| 15 | IFRS- Status Update Report at October 31, 2010 | Appendix 78 (Extracts Only) – MH Application |
| 16 | AUC Rule 026 & OEB Report EB-2008-0408 (Extracts Only) | AUC & OEB |
| 17 | IFRS- Regulatory Jurisdictional Comparison | PUB/MH PRE-ASK 17 |
| 18 | Finance Expense | PUB/MH I-36 (a) & (b) |
| 19 | Capitalized Finance Expense | PUB/MH II-35 (b) & (c) |
| 20 | Debt Management 1990- 2029 | PUB/MH I-69 (a) & (b); PUB/MH II- 170 (b) |
| 21 | Order 128/09 Board Directives | Order 128/09 Pages 135 to 137; PUB/MH I-46 (a), (b), (d), (e), (f) |
| 22 | Finance Expense/Debt Continuity/Debt Issues | PUB/MH I -35 (b), (d), (e), (h) |
| 23 | Depreciation & Amortization | PUB/MH I-37 Revised |
| 24 | Payments to Governments | PUB/MH II-14 (a); PUB/MH I-24; Schedule 4.10.0; PUB/MH I-41 |
| 25 | City of Winnipeg Assessment Notices | PUB/MH II-28 (a) |

# 1

TAB 1

**MANITOBA HYDRO**
**2010/11 & 2011/12 GENERAL RATE APPLICATION**

**LETTER OF APPLICATION**

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| | |
|---|---|
| **IN THE MATTER OF:** | *The Crown Corporations Public Review & Accountability Act* (Manitoba) |
| **IN THE MATTER OF:** | An Application by Manitoba Hydro for an Order of the Public Utilities Board Approving Increases to Electricity Rates |

**TO:** The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

1. Manitoba Hydro hereby applies to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to *The Crown Corporations Public Review & Accountability Act* for the following:

   a) Approval of rate schedules incorporating an across-the-board 2.9% average increase in General Consumers' rates effective April 1, 2010, which rate schedules are provided as Appendix 10.3 to this Application;

   b) Approval of rate schedules incorporating a further across-the-board 2.9% average increase in General Consumers' rates effective April 1, 2011, which rate schedules are provided as Appendix 10.4 to this Application;

   c) Final approval of all Surplus Energy Program ("SEP") *ex parte* rate orders as set forth in Appendix 10.7 as well as any additional SEP *ex parte* rate orders issued subsequent to the filing of this Application and prior to the PUB's order in this matter;

d) Final approval of Curtailable Rate Program *ex parte* Order 46/09 as well as any additional *ex parte* orders issued in respect of the Curtailable Rate Program discounts subsequent to the filing of this Application and prior to the PUB's order in this matter;

e) Final approval of Order 126/09, which order resulted from Manitoba Hydro's Application for Temporary Billing Demand Concessions for General Service Medium and Large customers related to impacts of the economic downturn. In Order 126/09, the PUB approved this Application, in the form of "a partial bill payment deferral program". Manitoba Hydro is requesting that the PUB's final approval of Order 126/09 include making permanent, billing concessions granted under such program.

Included in the rate schedules for which Manitoba Hydro is seeking approval is the reduction of the Basic Monthly Charge ("BMC") for Residential customers. Starting April 1, 2010 the proposal is to reduce the BMC from $6.85 to $5.85 with a further reduction to $4.85 beginning April 1, 2011. These decreases are being initiated to assist low income customers with low metered monthly consumption. The BMC for seasonal customers remains unchanged. The revenue decrease in both years of the application is being recovered in the energy rate proposed. See Tab 10 for further information about the reduction of the BMC.

2. The proposed General Consumers' rate increases of 2.9% effective April 1, 2010 and April 1, 2011 are projected to yield the Corporation additional revenue of $33.4 million in 2010/11 and further additional revenue of $35.1 million in 2011/12. The proposed rate increases reflect the appropriate balance between customer sensitivity and fiscal responsibility. In consideration of the economic downturn and its effects on ratepayers, 2.9% increases in each of the next two years are considered to be reasonable. For information, rate increases in other jurisdictions are: BC Hydro 9.7% (effective April 1, 2009; Nova Scotia Power 9.3% (effective January 1, 2009); SaskPower 8.5% (effective June 1, 2009); and Hydro-Québec 1.2% (effective April 1, 2009). The circumstances giving rise to the request for this increase are summarized in Tab 2 of the Application. Further information in support of the Application is included in Tabs 3 to 12 of this Application.

3. In addition to the documents filed with the Board, Manitoba Hydro will address the responses to a number of PUB directives in Tab 13.

Communication related to this Application should be addressed to Manitoba Hydro in the following fashion:

Manitoba Hydro
Attention: Patti Ramage
22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Telephone No. (204) 360-3946
Fax No. (204) 360-6147
E-Mail: pjramage@hydro.mb.ca

DATED at Winnipeg, Manitoba this 30th day of November, 2009.

**MANITOBA HYDRO**

"ORIGINAL SIGNED
BY PATRICIA J. RAMAGE"

Per: ______________________
Patricia J. Ramage

# 2

**ELECTRIC OPERATIONS** **PUB Exhibit** ____

**IFF09 - Actual- IFF10**

**PROJECTED INCOME STATEMENT ($MILLIONS)**

| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | |
|---|---|---|---|---|---|---|---|---|---|
| | IFF09 | IFF09 | IFF09 | Actual | Q1 | Q2 | IFF10 | IFF10 | |
| **For the Year ended March 31** | 2010 | 2011 | 2012 | 2010* | 2011 | 2011 | 2011 | 2012 | |
| **REVENUES** | | | | | | | | | |
| General Consumers at approved | 1,160 | 1,159 | 1,177 | | | | 1,161 | 1,195 | |
| additional * | - | 33 | 69 | | | | 33 ** | 69 | ** |
| Extraprovincial | 414 | 383 | 554 | 427 | | | 444 | 461 | |
| Other | 7 | 7 | 8 | 7 | | | 7 | 7 | |
| | 1,581 | 1,584 | 1,808 | 1,580 | | | 1,645 | 1,732 | |
| **EXPENSES** | | | | | | | | | |
| Operating and Administrative | 372 | 380 | 403 | 380 | | | 398 | 402 | |
| Finance Expense | 417 | 413 | 468 | 373 | | | 393 | 411 | |
| Depreciation and Amortization | 368 | 386 | 407 | 358 | | | 374 | 405 | |
| Fuel and Power Purchased | 103 | 132 | 248 | 104 | | | 121 | 187 | |
| Other Expenses | 201 | 195 | 197 | 205 | | | 211 | 206 | |
| | 1,461 | 1,506 | 1,723 | 1,420 | | | 1,496 | 1,611 | |
| **Net Income** | $ 121 | $ 78 | $ 87 | $ 160 | $100 | $150 | $ 149 | $ 125 | |
| Net income Change IFF10/Actual Vs. IFF09 | | | | 39 | | | 71 | 38 | $\boxed{\$148}$ |
| Retained Earnings IFF10 | | | | $ 2,206 | | | $ 2,354 | $ 2,479 | |
| Retained Earning IFF09 | | | | 2,183 | | | 2,261 | 2,331 | |
| Difference | | | | $ 23 | | | $ 93 | $ 148 | |

Sources:IFF09-1, IFF10, 59th Annual Report, Q1 & Q2 Quarterly Reports,

* The Financial Results for subsidiaries were removed from the segmented information included in the Fiscal 2010 Annual Report.

** Additional Consumer Revenue was adjusted to reflect the estimated requested rate increases in each of the 2011 & 2012 Test Years

# 3

Manitoba Hydro
2011 2012 GRA
PUB/MH I-2 (b) Analysis

| | % Rate Inc Req. | | % Approved | | Annul. $ Inc. ($Millions) | Inflation Rate |
|---|---|---|---|---|---|---|
| 1999/00 | 0% | | - | | - | 2.2% |
| 2000/01 | 0% | | - | | - | 2.5% |
| 2001/02 | -1.92% Uniform Rate Legislation | -1.92% | - | | (14.40) | 2.1% |
| 2002/03 | 0% | 0% | - | | - | 2.30% |
| 2003/04 | 0% Status Update | 0% | -0.72% Apr 1/03 BO 7/03 | | (6.50) | 0.90% |
| 2004/05 | 3.0% Apr 1/04 (two year application) | 3% | 5% Aug 1/04 Plus conditional 2.25% Apr 1/05 & 2.25% Oct 1/05 BO 101/04 & 143/04 | 5.0% | 32.30 | 2.70% |
| 2005/06 | 2.5% Apr 1/05 | 2.50% | 2.25% BO 34/05 | 2.3% | 21.80 | 2.40% |
| 2006/07 | 2.25% Feb 1/07 | 2.25% | 2.25% Mar 1/07 BO 20/07 | 2.3% | 23.00 | 2.00% |
| 2007/08 | Application filed Aug 2007 for rates eff. Apr 1/08 | | - | | - | 1.90% |
| 2008/09 | 2.9% Apr 1/08 | 2.90% | 5.0% Jul 1/08 Plus conditional 4.0% Apr 1/09 BO 90/08 | 5.0% | 52.40 | 2.20% |
| 2009/10 | 3.9% Apr 1/09 | 3.90% | 2.9% Apr 1/09 BO 32/09 | 2.9% | 32.80 | 0.60% |
| | **Actual Culmulative** | **15%** | | **17.4%** | **162.30** | **11.80%** |
| 2010/11* | 2.9% Apr 1/10 (two year application) | 2.90% | 2.8% Apr 1/10 Conditional BO 18/10 | 2.8% | 32.70 | 1.90% |
| | **Culmulative Increases with Interim Increase** | **17.45%** | | **20.2%** | **195.00** | **13.70%** |
| 2011/12 | 2.9% Apr 1/11 | 2.90% | TBD | 2.9% | 35.10 | 2.00% |
| | **Culmulative Increases with both applied for Increases** | **20.4%** | | **23.1%** | **230.10** | **15.70%** |

**PUB/MH I-2**

**Subject:** **Tab 2: Summary of Reasons For Application**
**Reference:** **Reason for Application Page 3 of 4**

**b)** **Please populate the following table for each of the years 1999/00 through 2011/12:**

| | 1999/ 2000 | 2000/01 | | 2011/12 |
|---|---|---|---|---|
| % Rate Increase Requested | | | | |
| % Rate increase approved by PUB | | | | |
| Annualized dollar increase from Rate increase | | | | |
| Annual Inflation Rate in Manitoba | | | | |

**ANSWER:**

| | % Rate Inc Req. | % Approved | Annul. $ Inc. | Inflation Rate |
|---|---|---|---|---|
| 1999/00 | 0% | - | - | 2.2% |
| 2000/01 | 0% | - | - | 2.5% |
| 2001/02 | -1.92%<br>Uniform Rate Legislation | - | ($14.4) million | 2.1% |
| 2002/03 | 0% | - | - | 2.3% |
| 2003/04 | 0%<br>Status Update | -0.72% Apr 1/03<br>BO 7/03 | ($6.5) million | 0.9% |
| 2004/05 | 3.0% Apr 1/04<br>(two year application) | 5% Aug 1/04<br>Plus conditional<br>2.25% Apr 1/05 & 2.25% Oct 1/05<br>BO 101/04 & 143/04 | $32.3 million | 2.7% |
| 2005/06 | 2.5% Apr 1/05 | 2.25%<br>BO 34/05 | $21.8 million | 2.4% |
| 2006/07 | 2.25% Feb 1/07 | 2.25% Mar 1/07<br>BO 20/07 | $23.1 million | 2.0% |

| | % Rate Inc Req. | % Approved | Annul. $ Inc. | Inflation Rate |
|---|---|---|---|---|
| 2007/08 | Application filed Aug 2007 for rates eff. Apr 1/08 | - | - | 1.9% |
| 2008/09 | 2.9% Apr 1/08 | 5.0% Jul 1/08<br>Plus conditional<br>4.0% Apr 1/09<br>BO 90/08 | $52.4 million | 2.2% |
| 2009/10 | 3.9% Apr 1/09 | 2.9% Apr 1/09<br>BO 32/09 | $32.8 million | 0.6% |
| 2010/11* | 2.9% Apr 1/10<br>(two year application) | 2.8% Apr 1/10<br>Conditional<br>BO 18/10 | $32.7 million | 1.9% (est) |
| 2011/12 | 2.9% Apr 1/11 | TBD | $35.1<br>If approved | 2.0% (est) |

* Pending interim PUB approval of rate schedules.

# 4

PUB-MH-I-199 (a)

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED OPERATING STATEMENT**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUES** | | | | | | | | | | | |
| General Consumers | | | | | | | | | | | |
| at approved rates | 1,160 | 1,159 | 1,177 | 1,191 | 1,204 | 1,229 | 1,244 | 1,260 | 1,272 | 1,283 | 1,297 |
| additional * | - | 33 | 69 | 113 | 161 | 212 | 266 | 322 | 381 | 442 | 508 |
| Extraprovincial | 414 | 383 | 554 | 583 | 615 | 590 | 701 | 729 | 742 | 894 | 1,093 |
| Other | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| | 1,581 | 1,584 | 1,808 | 1,895 | 1,987 | 2,039 | 2,219 | 2,320 | 2,404 | 2,628 | 2,907 |
| **EXPENSES** | | | | | | | | | | | |
| Operating and Administrative | 372 | 380 | 403 | 411 | 420 | 428 | 437 | 445 | 467 | 478 | 497 |
| Finance Expense (Before Corp Allocation) | 423 | 419 | 474 | 532 | 533 | 551 | 536 | 552 | 594 | 680 | 885 |
| Finance Expense | 417 | 413 | 468 | 525 | 527 | 544 | 529 | 545 | 587 | 674 | 878 |
| Depreciation and Amortization | 368 | 386 | 407 | 435 | 446 | 466 | 476 | 481 | 501 | 532 | 566 |
| Water Rentals and Assessments | 120 | 110 | 111 | 113 | 114 | 114 | 115 | 115 | 115 | 115 | 124 |
| Fuel and Power Purchased | 103 | 132 | 248 | 250 | 260 | 269 | 297 | 341 | 363 | 441 | 419 |
| Capital and Other Taxes | 73 | 76 | 77 | 80 | 85 | 92 | 100 | 109 | 115 | 121 | 124 |
| Corporate Allocation | 8 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| | 1,460 | 1,505 | 1,723 | 1,824 | 1,860 | 1,922 | 1,963 | 2,046 | 2,156 | 2,370 | 2,617 |
| Non-controlling Interest | - | - | 1 | 1 | (2) | (5) | (9) | (11) | (12) | (15) | (14) |
| **Net Income** | 121 | 78 | 87 | 72 | 125 | 113 | 248 | 263 | 235 | 244 | 276 |
| *Additional General Consumers Revenue | | | | | | | | | | | |
| Percent Increase | | 2.90% | 2.90% | 3.50% | 3.50% | 3.50% | 3.50% | 3.50% | 3.50% | 3.50% | 3.50% |
| Cumulative Percent Increase | | 2.90% | 5.88% | 9.59% | 13.43% | 17.40% | 21.50% | 25.76% | 30.16% | 34.71% | 39.43% |
| **Financial Ratios** | | | | | | | | | | | |
| Debt | 74% | 75% | 76% | 76% | 78% | 79% | 80% | 80% | 80% | 80% | 80% |
| Interest Coverage | 1.24 | 1.14 | 1.14 | 1.11 | 1.19 | 1.15 | 1.30 | 1.28 | 1.23 | 1.22 | 1.22 |
| Capital Coverage (excl Major Gen.) | 1.37 | 1.11 | 1.14 | 1.31 | 1.25 | 1.53 | 1.89 | 1.87 | 1.96 | 2.21 | 2.71 |

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED OPERATING STATEMENT**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|
| **REVENUES** | | | | | | | | | |
| General Consumers | | | | | | | | | |
| at approved rates | 1,312 | 1,327 | 1,342 | 1,357 | 1,374 | 1,393 | 1,413 | 1,433 | 1,450 |
| additional * | 550 | 594 | 639 | 687 | 736 | 789 | 844 | 901 | 959 |
| Extraprovincial | 1,201 | 1,223 | 1,379 | 1,758 | 1,940 | 1,908 | 1,903 | 1,928 | 1,950 |
| Other | 9 | 9 | 10 | 10 | 10 | 10 | 10 | 11 | 11 |
| | 3,073 | 3,153 | 3,370 | 3,812 | 4,060 | 4,100 | 4,170 | 4,273 | 4,370 |
| **EXPENSES** | | | | | | | | | |
| Operating and Administrative | 509 | 519 | 536 | 547 | 558 | 569 | 580 | 592 | 603 |
| Finance Expense (Before Corp Allocation) | 965 | 858 | 897 | 1,078 | 1,173 | 1,133 | 1,101 | 1,044 | 986 |
| Finance Expense | 958 | 851 | 890 | 1,071 | 1,166 | 1,126 | 1,094 | 1,037 | 980 |
| Depreciation and Amortization | 592 | 598 | 626 | 687 | 731 | 747 | 764 | 767 | 777 |
| Water Rentals and Assessments | 129 | 130 | 136 | 150 | 154 | 155 | 155 | 156 | 157 |
| Fuel and Power Purchased | 435 | 460 | 474 | 460 | 492 | 420 | 396 | 425 | 446 |
| Capital and Other Taxes | 117 | 121 | 126 | 128 | 128 | 129 | 129 | 130 | 131 |
| Corporate Allocation | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| | 2,750 | 2,688 | 2,798 | 3,051 | 3,239 | 3,156 | 3,127 | 3,116 | 3,103 |
| Non-controlling Interest | (25) | (27) | (28) | (29) | (30) | (34) | (38) | (41) | (43) |
| **Net Income** | 299 | 439 | 544 | 732 | 791 | 911 | 1,005 | 1,116 | 1,224 |
| *Additional General Consumers Revenue | | | | | | | | | |
| Percent Increase | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% |
| Cumulative Percent Increase | 42.22% | 45.06% | 47.96% | 50.92% | 53.94% | 57.02% | 60.16% | 63.36% | 66.63% |
| **Financial Ratios** | | | | | | | | | |
| Debt | 79% | 78% | 76% | 74% | 70% | 66% | 62% | 57% | 51% |
| Interest Coverage | 1.24 | 1.36 | 1.45 | 1.59 | 1.66 | 1.79 | 1.90 | 2.05 | 2.22 |
| Capital Coverage (excl Major Gen.) | 2.32 | 2.26 | 2.30 | 2.59 | 2.50 | 2.81 | 2.95 | 3.19 | 3.19 |

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED BALANCE SHEET**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **ASSETS** | | | | | | | | | | | |
| Plant in Service | 12,527 | 13,034 | 15,075 | 15,566 | 15,982 | 16,691 | 17,127 | 17,837 | 20,301 | 21,599 | 25,001 |
| Accumulated Depreciation | (4,663) | (5,018) | (5,398) | (5,805) | (6,216) | (6,649) | (7,091) | (7,540) | (8,010) | (8,514) | (9,052) |
| Net Plant in Service | 7,865 | 8,015 | 9,677 | 9,761 | 9,765 | 10,042 | 10,035 | 10,297 | 12,292 | 13,085 | 15,950 |
| Construction in Progress | 1,947 | 2,458 | 1,341 | 1,818 | 2,838 | 3,854 | 5,532 | 6,948 | 6,159 | 6,446 | 4,168 |
| Current and Other Assets | 2,767 | 2,735 | 2,871 | 2,926 | 2,708 | 2,860 | 3,047 | 3,259 | 3,564 | 3,348 | 3,683 |
| Goodwill | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 |
| | 12,621 | 13,251 | 13,931 | 14,546 | 15,353 | 16,798 | 18,656 | 20,545 | 22,057 | 22,922 | 23,843 |
| **LIABILITIES AND EQUITY** | | | | | | | | | | | |
| Long-Term Debt | 7,800 | 8,596 | 9,054 | 8,769 | 10,349 | 11,505 | 13,123 | 14,412 | 15,346 | 16,429 | 14,147 |
| Current and Other Liabilities | 2,156 | 1,926 | 2,119 | 2,916 | 2,106 | 2,306 | 2,333 | 2,692 | 3,045 | 2,586 | 5,514 |
| Contributions in Aid of Construction | 290 | 288 | 284 | 280 | 276 | 275 | 274 | 273 | 272 | 271 | 271 |
| Retained Earnings | 2,183 | 2,261 | 2,331 | 2,403 | 2,528 | 2,641 | 2,889 | 3,153 | 3,388 | 3,632 | 3,908 |
| Accumulated Other Comprehensive Income | 192 | 178 | 143 | 178 | 94 | 71 | 38 | 17 | 6 | 3 | 3 |
| | 12,621 | 13,251 | 13,931 | 14,546 | 15,353 | 16,798 | 18,656 | 20,545 | 22,057 | 22,922 | 23,843 |

PUB-MH-I-199 (a)

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED BALANCE SHEET**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|
| **ASSETS** | | | | | | | | | |
| Plant in Service | 26,067 | 26,505 | 30,392 | 33,459 | 34,732 | 35,524 | 36,105 | 36,821 | 37,414 |
| Accumulated Depreciation | (9,616) | (10,190) | (10,793) | (11,461) | (12,177) | (12,911) | (13,663) | (14,420) | (15,188) |
| Net Plant in Service | 16,451 | 16,316 | 19,599 | 21,998 | 22,556 | 22,613 | 22,441 | 22,401 | 22,226 |
| Construction in Progress | 4,523 | 5,453 | 3,111 | 877 | 270 | 119 | 207 | 205 | 338 |
| Current and Other Assets | 3,886 | 3,422 | 3,704 | 4,315 | 5,201 | 5,650 | 6,794 | 8,013 | 9,284 |
| Goodwill | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 |
| | 24,902 | 25,233 | 26,456 | 27,232 | 28,068 | 28,424 | 29,484 | 30,661 | 31,890 |
| **LIABILITIES AND EQUITY** | | | | | | | | | |
| Long-Term Debt | 17,406 | 17,838 | 18,640 | 18,642 | 18,044 | 18,047 | 18,049 | 17,991 | 17,743 |
| Current and Other Liabilities | 3,015 | 2,476 | 2,354 | 2,394 | 3,036 | 2,477 | 2,527 | 2,642 | 2,891 |
| Contributions in Aid of Construction | 272 | 272 | 273 | 274 | 276 | 277 | 280 | 283 | 287 |
| Retained Earnings | 4,207 | 4,645 | 5,190 | 5,922 | 6,713 | 7,623 | 8,629 | 9,745 | 10,969 |
| Accumulated Other Comprehensive Income | 2 | 1 | (0) | 0 | 0 | 0 | 0 | 0 | 0 |
| | 24,902 | 25,233 | 26,456 | 27,232 | 28,068 | 28,424 | 29,484 | 30,661 | 31,890 |

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED CASH FLOW STATEMENT**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **OPERATING ACTIVITIES** | | | | | | | | | | | |
| Cash Receipts from Customers | 1,581 | 1,584 | 1,808 | 1,895 | 1,987 | 2,039 | 2,219 | 2,320 | 2,404 | 2,628 | 2,907 |
| Cash Paid to Suppliers and Employees | (646) | (690) | (827) | (845) | (872) | (898) | (946) | (1,010) | (1,059) | (1,156) | (1,168) |
| Interest Paid | (453) | (423) | (479) | (541) | (550) | (549) | (554) | (566) | (634) | (725) | (915) |
| Interest Received | 29 | 22 | 14 | 16 | 14 | 4 | 15 | 26 | 36 | 39 | 33 |
| | 511 | 493 | 516 | 524 | 579 | 596 | 734 | 769 | 746 | 786 | 859 |
| **FINANCING ACTIVITIES** | | | | | | | | | | | |
| Proceeds from Long-Term Debt | 745 | 800 | 600 | 540 | 1,600 | 1,400 | 1,800 | 1,800 | 1,800 | 1,400 | 1,000 |
| Sinking Fund Withdrawals | 262 | 227 | 27 | 103 | 483 | - | 3 | - | - | 456 | 171 |
| Retirement of Long-Term Debt | (355) | (304) | (27) | (121) | (849) | (100) | (262) | (201) | (530) | (869) | (321) |
| Other | (35) | (10) | 19 | (10) | (14) | (12) | (13) | (14) | (15) | (26) | (15) |
| | 618 | 713 | 619 | 512 | 1,220 | 1,288 | 1,528 | 1,585 | 1,255 | 961 | 835 |
| **INVESTING ACTIVITIES** | | | | | | | | | | | |
| Property, Plant and Equipment, net of contribution | (1,113) | (1,079) | (1,004) | (989) | (1,457) | (1,737) | (2,125) | (2,135) | (1,685) | (1,619) | (1,259) |
| Sinking Fund Payment | (94) | (99) | (98) | (116) | (176) | (107) | (201) | (159) | (242) | (200) | (256) |
| Other | (36) | (20) | (16) | (17) | (15) | (31) | (29) | (40) | (28) | (27) | (27) |
| | (1,243) | (1,198) | (1,118) | (1,123) | (1,648) | (1,876) | (2,355) | (2,334) | (1,954) | (1,846) | (1,543) |
| **Net Increase (Decrease) in Cash** | (114) | 8 | 17 | (86) | 151 | 9 | (92) | 21 | 47 | (98) | 151 |
| **Cash at Beginning of Year** | 66 | (48) | (40) | (23) | (109) | 41 | 51 | (41) | (21) | 26 | (72) |
| **Cash at End of Year** | (48) | (40) | (23) | (109) | 41 | 51 | (41) | (21) | 26 | (72) | 79 |

**ELECTRIC OPERATIONS (MH09-1)**
**PROJECTED CASH FLOW STATEMENT**
**20 YEAR FINANCIAL OUTLOOK**
**(In Millions of Dollars)**

| ***For the year ended March 31*** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** |
|---|---|---|---|---|---|---|---|---|---|
| **OPERATING ACTIVITIES** | | | | | | | | | |
| Cash Receipts from Customers | 3,073 | 3,153 | 3,370 | 3,812 | 4,060 | 4,100 | 4,170 | 4,273 | 4,370 |
| Cash Paid to Suppliers and Employees | (1,194) | (1,234) | (1,277) | (1,289) | (1,337) | (1,279) | (1,266) | (1,308) | (1,343) |
| Interest Paid | (1,000) | (894) | (908) | (1,099) | (1,206) | (1,178) | (1,137) | (1,092) | (1,046) |
| Interest Received | 30 | 27 | 4 | 3 | 11 | 15 | 10 | 18 | 27 |
| | 909 | 1,052 | 1,189 | 1,426 | 1,528 | 1,659 | 1,777 | 1,891 | 2,009 |
| **FINANCING ACTIVITIES** | | | | | | | | | |
| Proceeds from Long-Term Debt | 1,000 | 600 | 800 | - | - | - | - | - | - |
| Sinking Fund Withdrawals | 285 | 741 | 171 | - | - | 341 | - | - | 60 |
| Retirement of Long-Term Debt | (285) | (744) | (171) | - | - | (600) | - | - | (60) |
| Other | 11 | (26) | (23) | (24) | (24) | (25) | (27) | (29) | (30) |
| | 1,011 | 571 | 777 | (24) | (24) | (284) | (27) | (29) | (30) |
| **INVESTING ACTIVITIES** | | | | | | | | | |
| Property, Plant and Equipment, net of contribution | (1,443) | (1,359) | (1,536) | (820) | (651) | (622) | (651) | (695) | (706) |
| Sinking Fund Payment | (292) | (349) | (208) | (183) | (188) | (193) | (179) | (183) | (188) |
| Other | (33) | (38) | (28) | (32) | (29) | (30) | (33) | (31) | (31) |
| | (1,768) | (1,746) | (1,772) | (1,035) | (868) | (845) | (862) | (909) | (925) |
| **Net Increase (Decrease) in Cash** | 152 | (124) | 194 | 367 | 636 | 529 | 887 | 953 | 1,053 |
| **Cash at Beginning of Year** | 79 | 231 | 107 | 301 | 669 | 1,305 | 1,834 | 2,721 | 3,674 |
| **Cash at End of Year** | 231 | 107 | 301 | 669 | 1,305 | 1,834 | 2,721 | 3,674 | 4,727 |

# 5

**PUB/MH II-194**

**Reference:** **20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load**

**a) Please confirm the following domestic load forecast history:**

| | Net Firm Energy Load Forecast | | Difference (GWh) | Domestic Sales at Generation | | |
|---|---|---|---|---|---|---|
| | 2007/08 (GWh) | 2008/09 (GWh) | | IFF 08-1 Assumptions (GWh) | PUB/MH I-209 IFF 09 Assumptions (GWh) | IFF Difference (GWh) |
| 2009/10 | 24,937 | 24,080 | -857 | 24,875 | 23,968 | -907 |
| 2010/11 | 25,713 | 24,600 | -1,113 | 25,488 | 24,346 | -1,142 |
| 2011/12 | 26,362 | 25,169 | -1,193 | 26,050 | 24,718 | -1,332 |
| 2012/13 | 26,922 | 25,599 | -1,343 | 26,544 | 25,075 | -1,469 |
| 2013/14 | 27,241 | 26,012 | -1,229 | 26,787 | 25,413 | -1,374 |
| 2014/15 | 27,531 | 26,618 | -913 | 27,049 | 26,030 | -1,019 |
| 2015/16 | 27,827 | 26,973 | -854 | 27,296 | 26,439 | -857 |
| 2020/21 | 29,432 | 28,654 | -778 | 28,789 | 27,551 | -1,238 |
| 2025/26 | 31,108 | 30,516 | -592 | 30,324 | 29,379 | -945 |

**ANSWER:**

The following table contains the correct figures and references, including:

- Correct references to the forecasts (i.e. the forecast figures provided are associated with the May 2008 (2008/09 - 2028/29) and the May 2009 (2009/10 - 2029/30) electric forecasts;
- The correct firm energy for the May 2009 forecast during 2011/12 is 25, 159; and
- The correct forecast difference for 2011/12 is -1,203 and the correct difference for 2012/13 is -1,323.

The load forecast and IFF figures differ because the IFF excludes DSM impacts and includes several additional factors in domestic sales, such as station service and losses arising as a result of generation and transmission facilities.

| | Net Firm Energy Load Forecast | | Difference (GWh) | Domestic Sales at Generation | | |
|---|---|---|---|---|---|---|
| | May 2008 (GWh) | May 2009 (GWh) | | IFF 08-1 Assumptions (GWh) | PUB/MH I-209 IFF 09 Assumptions (GWh) | IFF Difference (GWh) |
| **2009/10** | 24,937 | 24,080 | -857 | 24,875 | 23,968 | -907 |
| **2010/11** | 25,713 | 24,600 | -1,113 | 25,488 | 24,346 | -1,142 |
| **2011/12** | 26,362 | 25,159 | -1,203 | 26,050 | 24,718 | -1,332 |
| **2012/13** | 26,922 | 25,599 | -1,323 | 26,544 | 25,075 | -1,469 |
| **2013/14** | 27,241 | 26,012 | -1,229 | 26,787 | 25,413 | -1,374 |
| **2014/15** | 27,531 | 26,618 | -913 | 27,049 | 26,030 | -1,019 |
| **2015/16** | 27,827 | 26,973 | -854 | 27,296 | 26,439 | -857 |
| **2020/21** | 29,432 | 28,654 | -778 | 28,789 | 27,551 | -1,238 |
| **2025/26** | 31,108 | 30,516 | -592 | 30,324 | 29,379 | -945 |

# 6

**PUB/MH II-45**

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **PUB/MH I-45 (b) Assumptions**

**a) Please provide an expanded table including export transmission losses and all assumptions to 2029.**

**ANSWER:**

Please see attached table.

Transmission charges are netted to export sales for the purposes of the average price calculation. Merchant sales and purchases are excluded from the calculation.

**IFF09 Export Revenue Assumptions**

| (in GWh) | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | 33,124 | 30,525 | 30,067 | 30,789 | 30,989 | 30,913 | 30,929 | 31,078 | 30,812 | 30,755 | 33,518 |
| MH Thermal Generation | 152 | 159 | 432 | 437 | 441 | 444 | 497 | 531 | 580 | 591 | 521 |
| Import Energy (including Wind) | 733 | 1,508 | 2,616 | 2,576 | 2,569 | 2,608 | 2,663 | 2,717 | 2,794 | 3,789 | 3,459 |
| Manitoba Domestic Energy Sales | 23,968 | 24,346 | 24,728 | 25,075 | 25,413 | 26,030 | 26,439 | 26,790 | 26,743 | 26,929 | 27,229 |
| Total Export Sales | 9,149 | 7,122 | 7,841 | 8,150 | 8,020 | 7,430 | 7,181 | 7,082 | 7,006 | 7,746 | 9,598 |
| Export Transmission Losses | 891 | 724 | 546 | 577 | 566 | 504 | 469 | 454 | 438 | 461 | 670 |
| Total Supply | 34,009 | 32,192 | 33,114 | 33,802 | 33,998 | 33,964 | 34,089 | 34,326 | 34,186 | 35,136 | 37,497 |
| Total Demand | 34,008 | 32,192 | 33,114 | 33,802 | 33,998 | 33,964 | 34,089 | 34,326 | 34,186 | 35,136 | 37,497 |

| (in Millions of Dollars) | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | $ 111 | $ 102 | $ 100 | $ 103 | $ 104 | $ 103 | $ 103 | $ 104 | $ 103 | $ 103 | $ 112 |
| MH Thermal Generation | 8 | 8 | 41 | 41 | 44 | 45 | 55 | 61 | 70 | 75 | 77 |
| Import Energy (including Wind) | 36 | 56 | 171 | 172 | 177 | 184 | 195 | 206 | 217 | 289 | 264 |
| Total Manitoba Domestic Energy Sales | 1,160 | 1,193 | 1,246 | 1,305 | 1,365 | 1,441 | 1,510 | 1,582 | 1,653 | 1,725 | 1,805 |
| Total Export Sales | 332 | 292 | 517 | 545 | 575 | 549 | 653 | 654 | 665 | 816 | 1,013 |

| Average Price ($/MWh) | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | $ 3.36 | $ 3.35 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 |
| MH Thermal Generation | 52.79 | 52.09 | 95.96 | 94.72 | 99.73 | 102.53 | 109.86 | 115.37 | 120.73 | 127.24 | 147.20 |
| Import Energy (including Wind) | 49.69 | 37.12 | 65.29 | 66.78 | 69.08 | 70.54 | 73.36 | 75.75 | 77.65 | 76.20 | 76.21 |
| Total Manitoba Domestic Energy Sales | 48.40 | 48.99 | 50.39 | 52.03 | 53.69 | 55.36 | 57.13 | 59.05 | 61.80 | 64.07 | 66.30 |
| Total Export Sales | 36.24 | 41.02 | 65.92 | 66.90 | 71.73 | 73.96 | 90.88 | 92.33 | 94.97 | 105.33 | 105.58 |

## IFF09 Export Revenue Assumptions

| (in GWh) | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | 34,866 | 34,976 | 36,781 | 40,572 | 41,767 | 42,041 | 41,937 | 42,015 | 42,055 |
| MH Thermal Generation | 599 | 645 | 730 | 597 | 597 | 386 | 344 | 348 | 347 |
| Import Energy (including Wind) | 3,359 | 3,437 | 3,233 | 3,178 | 3,380 | 3,023 | 3,025 | 3,068 | 3,106 |
| Manitoba Domestic Energy Sales | 27,551 | 27,893 | 28,363 | 28,638 | 28,979 | 29,379 | 29,795 | 30,215 | 30,600 |
| Total Export Sales | 10,516 | 10,426 | 11,530 | 14,541 | 15,510 | 14,843 | 14,331 | 14,064 | 13,787 |
| Export Transmission Losses | 757 | 739 | 851 | 1,169 | 1,255 | 1,228 | 1,180 | 1,151 | 1,122 |
| Total Supply | 38,824 | 39,058 | 40,744 | 44,347 | 45,744 | 45,450 | 45,306 | 45,431 | 45,509 |
| Total Demand | 38,824 | 39,058 | 40,744 | 44,347 | 45,744 | 45,450 | 45,306 | 45,431 | 45,509 |

| (in Millions of Dollars) | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | $ 116 | $ 117 | $ 123 | $ 136 | $ 140 | $ 140 | $ 140 | $ 140 | $ 141 |
| MH Thermal Generation | 90 | 100 | 115 | 97 | 102 | 66 | 61 | 64 | 66 |
| Import Energy (including Wind) | 265 | 278 | 276 | 277 | 304 | 266 | 245 | 270 | 287 |
| Total Manitoba Domestic Energy Sales | 1,805 | 1,805 | 1,805 | 1,805 | 1,805 | 1,805 | 1,805 | 1,805 | 1,805 |
| Total Export Sales | 1,120 | 1,140 | 1,294 | 1,671 | 1,852 | 1,818 | 1,811 | 1,835 | 1,855 |

| Average Price ($/MWh) | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 |
|---|---|---|---|---|---|---|---|---|---|
| MH Hydraulic Generation | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 | $ 3.34 |
| MH Thermal Generation | 150.74 | 155.41 | 157.98 | 163.00 | 170.49 | 172.36 | 177.17 | 183.42 | 190.27 |
| Import Energy (including Wind) | 78.86 | 81.00 | 85.30 | 87.29 | 90.06 | 88.04 | 81.13 | 88.03 | 92.53 |
| Total Manitoba Domestic Energy Sales | 65.52 | 64.72 | 63.65 | 63.04 | 62.29 | 61.45 | 60.59 | 59.75 | 58.99 |
| Total Export Sales | 106.52 | 109.36 | 112.25 | 114.91 | 119.38 | 122.51 | 126.39 | 130.44 | 134.52 |

## PUB SUPPLEMENTAL TO PUB/MH II-193

Reference: Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions

b) Please illustrate for 2008/09 and 2009/10 the revenue levels ($M) and sales volumes (GWh) for each of these transactions.

**MH's ANSWER with PUB (in bold) subtotals and average unit prices :**

| | 2008/09 | | | 2009/10 | | |
|---|---|---|---|---|---|---|
| | **GWh** | **$M (Cdn)** | **¢/KWh** | **GWh** | **$M (Cdn)** | **¢/KWh** |
| Dependable | 4,087 | 233 | **5.70** | 3,263 | 186 | **5.70** |
| Opportunity Bilateral | 1,305 | 101 | **7.74** | 2,628 | 60 | **2.28** |
| Day Ahead | 4,040 | 122 | **3.02** | 3,111 | 59 | **1.90** |
| Real Time | 690 | 60 | **8.70** | 1,858 | 71 | **3.82** |
| **Subtotal** | **10,122** | **516** | **5.10** | **10,860** | **376** | **3.46** |
| Merchant | 1,598 | 86 | **5.38** | 775 | 26 | **3.35** |

**PUB** **SUPPLEMENTAL TO PUB/MH II-193**

Reference: Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions

c) Please provide a similar definition and illustration of import transactions for 2008/09 and 2009/10.

**MH's ANSWER with PUB (in bold) subtotals and average unit prices :**

| | 2008/09 | | | 2009/10 | | |
|---|---|---|---|---|---|---|
| | GWh | $M (Cdn) | ¢/KWh | GWh | $M (Cdn) | ¢/KWh |
| Dependable | 395 | 21 | **5.32** | 513 | 21 | **4.09** |
| Opportunity Bilateral | 9 | 7 | **N/A** | 6 | 1 | **N/A** |
| Day Ahead | 72 | 2 | **2.78** | 75 | 2 | **2.67** |
| Real Time | 505 | 22 | **4.36** | 726 | 14 | **1.93** |
| **Subtotal** | **981** | **52** | **5.30** | **1,320** | **36** | **2.73** |
| Merchant | 1,598 | 80 | **5.01** | 775 | 25 | **3.23** |

7

Canadian Gas Association
Association canadienne du gaz

# North American Natural Gas Supply

## Canadian Gas Association
## 2010 Supply Bulletin

## Executive Summary

The North American abundant natural gas supply 'portfolio' is undergoing a dramatic diversification with the addition of unconventional gas sources including coal bed methane (CBM) and shale gas[1] being added to the supply mix. Unconventional gas' share of the supply mix has risen from 9% in 2000 to 25% in 2010 driven by a 15-fold increase in gas from shale deposits.

The emergence of shale gas is the result of technological advancements in drilling and production techniques – such as horizontal drilling and multi-stage fraccing – have allowed producers to unlock increasingly higher volumes of gas at lower costs.

Figure 1 illustrates North American natural gas production to 2030. The fastest growing supply source is shale gas which the U.S. Energy Information Agency will increase from less than 0.5 Tcf/year in 2000 to 5.5 Tcf in 2030 representing nearly 30% of U.S. supply.

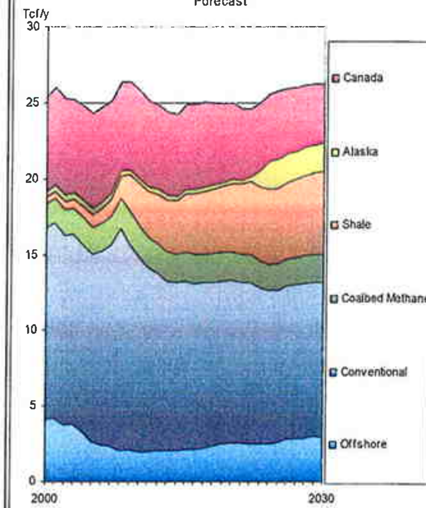
In Canada, forecasts from the National Energy Board show Canadian unconventional production will grow at similar rates to that of the United States driven by the Horn River shale and the Montney shale/tight gas plays in northeast British Columbia.

The growth of unconventional supply comes as producers seek additional prospects for development, in addition to their conventional assets, which offer economic return at increasingly lower cost. The advancement of unconventional gas supply has contributed to lower price levels for consumers, spurred new pipeline construction in production areas and provided a new source of royalty and licensing revenues for governments.

Ultimately, the success of unconventional development in the North American natural gas supply is contingent on the complex interplay of technology, cost, environment benefits, and market prices for natural gas and other energy products and services.

The following paper examines the changes seen in the domestic North American natural gas supply picture and the impact of unconventional gas development on natural gas supply, prices and markets.

Figure 1: North American Natural Gas Production Forecast




Sources: NEB (2009), EIA

**Unconventional Gas Types**

**Shale Gas**
found in extremely fine-grained, essentially impermeable sedimentary rocks requiring complex reservoir stimulation to help the natural gas flow.

**Tight Gas**
Found in the pore space of sedimentary rocks that have very low permeability. Reservoir stimulation is required to recover tight gas resources.

**Coal Bed Methane**
formed during the process of coalification. In this process, methane is generated and trapped as peat turns into lignite and later into coal. In coal seams, methane is primarily stored by adsorption to solid hydrocarbon molecules. A range of reservoir stimulation methods are used to recover the resource.

## What is Conventional and Unconventional Natural Gas?

Conventional natural gas is natural gas contained in sandstone or limestone formations, which have high levels of porosity and permeability allowing gas to flow easily from the reservoir up through a single well bore allowing reservoirs to be developed with traditional vertical wells.

Initial conventional gas well production rates are relatively high but their depletion is also relatively fast and a conventional gas well may be fully depleted in 5 years. Increasingly, conventional gas pools are requiring more precise geological and/or geophysical analysis to pinpoint their exact location as large conventional finds are becoming increasingly scarce in mature exploration basins across North America.
Unconventional natural gas is the term used for gas contained in low porosity formations typically spread over larger geographic areas. As a result pinpointing these reservoirs and choosing drilling sites is considerably less difficult. While finding an unconventional gas reservoir may be easier, production can be costly requiring specialized horizontal drilling, completion (fraccing), and production technology that allow economic gas flow rates.

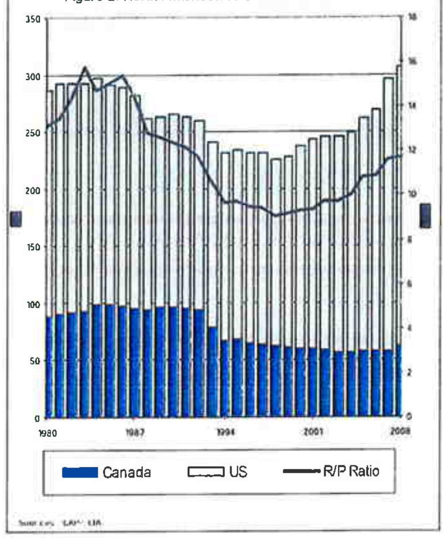
Renewable natural gas is methane obtained from biomass which has been upgraded to

[1]Unconventional gas includes shale and CBM. Tight gas production - which is significant at around 25% of North American supply - is now captured within conventional gas production.

a quality similar to fossil natural gas. By upgrading the quality to that of natural gas, it becomes possible to distribute the gas to customers through the existing natural gas pipeline system and burned within existing appliances.

Canadian wastes that are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal waste streams. The potential of Canada's RNG is significant and equal to 130% of current residential and commercial use. In addition to energy benefits, capture of RNG from Canadian wastes contributes to GHG reductions by capturing methane emissions from landfills and animal manures and reducing the need for natural gas from fossil sources. Total potential GHG reductions were estimated at 107 Mt CO2 eq/yr for Canada with the largest amounts found in Quebec, Ontario and BC.

Figure 2: North American Reserves and Production




## North American Conventional and Unconventional Natural Gas Supply Potential

Proven Gas Reserves

Proven reserves are quantities of gas immediately available in drilled reservoirs that are connected to pipelines and markets. Reserves are the best indication for estimating future near term natural gas production capabilities. The U.S. and Canada have a combined proven natural gas reserves base of 307 Tcf (245 Tcf in the U.S. and 62 Tcf in Canada).

In recent years, North American producers have been adding record volumes of natural gas to their proved reserve 'bank' as illustrated in Figure 2. In the years 2007 and 2008, U.S. natural gas producers added 34 Tcf to proven reserves with 2008 reserve additions totalling 27 Tcf making that year the single largest annual addition in U.S. history. In 2008, Canadian producers added 4 Tcf which is one of the largest additions in Canadian history. As a result the R/P ratio in North America increased from 9 years in 1993 to 12 years in 2009 – a 30 % increase.

New unconventional gas finds in Canada and the U.S. offer tremendous upside potential for North American reserve levels as producers continue to drill and evaluate their shale gas formations.

Natural Gas Resources – 2000 vs. 2009

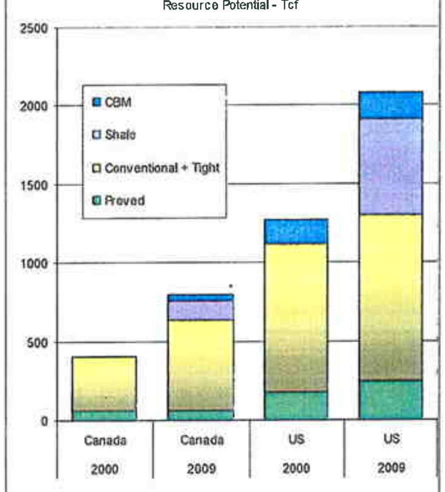
Figure 3 illustrates the transformation in U.S. and Canadian natural gas resources (i.e., quantities of discovered resources [those that have been found but have yet to be connected to pipelines due to lack of infrastructure such as Mackenzie and Alaska gas resources] and also undiscovered resources [volumes that geologists believe will be found in the future]) and proved reserves in the years 2000 and 2009.

The total North American resources + reserves in 2009 measured 2,870 Tcf, a 72% increase compared to 1,672 Tcf in 2000. The primary driver of higher gas resources are being driven by new natural gas discoveries in both conventional and unconventional fields.

In Canada, the reserves + resources volume has increased from 404 Tcf in 2000 to 794 Tcf in 2009 – a 97% increase. The United States has undergone a similar transformation with the reserve + resource base increasing from 1,268 Tcf in 2000 to 2,076 Tcf in 2009 – a 64% increase.

The long term future potential for unconventional gas is highlighted by the large volumes of shale gas where the North American recoverable potential is estimated at approximately 743 Tcf with 616 Tcf of shale gas in the U.S. and 128 Tcf in Canada. Shale gas potential in North America is backstopped by vast resources held within other unconventional gas sources combined with significant untapped conventional and renewable natural gas resources.

Figure 3: North American Marketable Gas Reserve and Resource Potential - Tcf

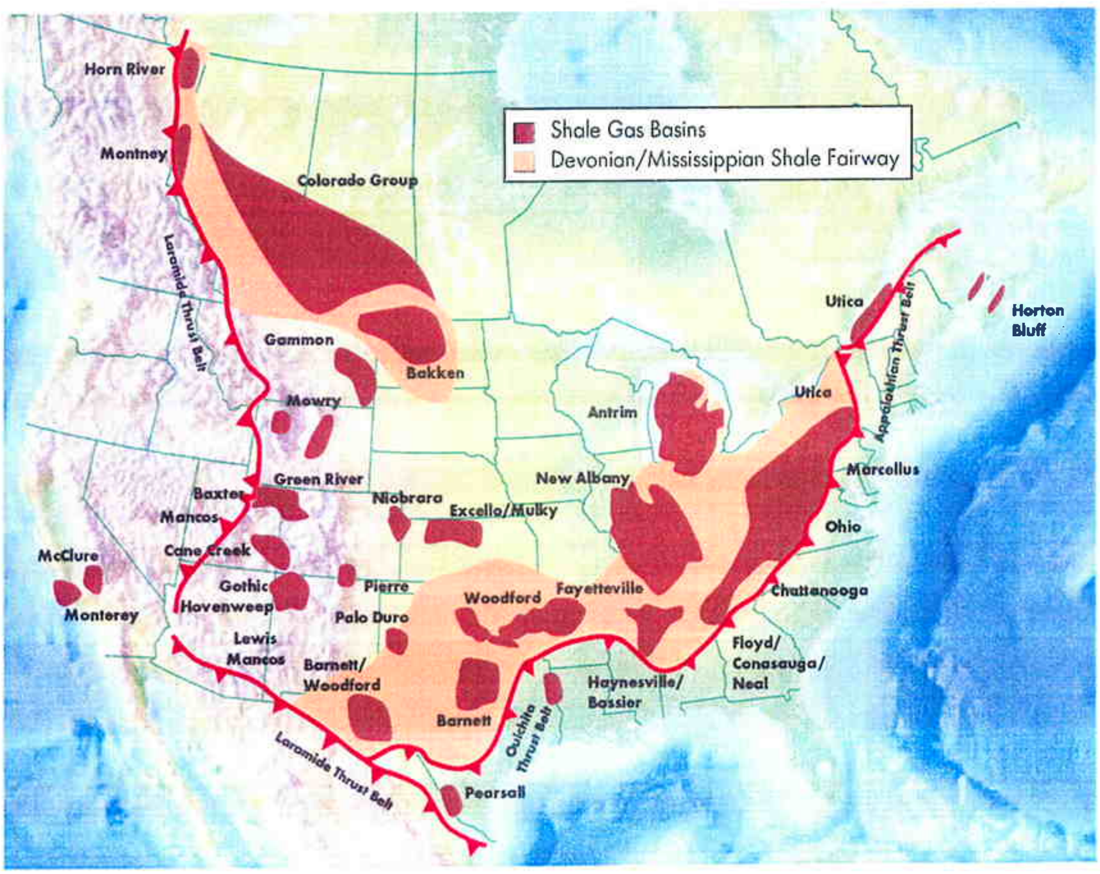



Sources CAPP,CGUG, EIA, Canadian Gas Potential Committee, US Gas Potential Committee

**Shale Gas Resource Location**

Shale gas resources are distributed throughout Canada and the U.S. (see Map 1) in traditional natural gas development areas such as the US Gulf Coast and Western Canada and also in areas largely unfamiliar to natural gas development such as Quebec and the U.S. Northeast. The most advanced shale plays exist in the U.S. Gulf Coast (Barnett, Fayettville, Woodford, Haynesville), the Northeast (Marcellus) and northeastern British Columbia (Horn River and Montney).

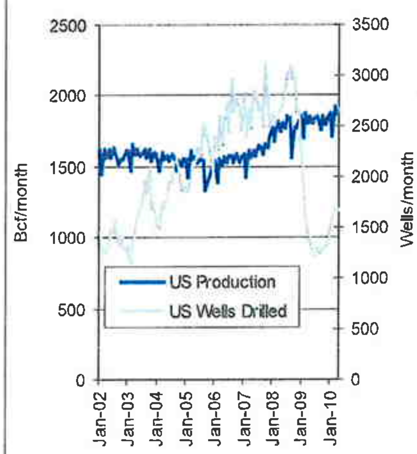
**MAP 1: North American Shale Gas Deposits**




Production from these shales has increased significantly since 2001 and combined the account for approximately 15% of North America's natural gas supply (as of mid-2010). Future shale production is expected to be significant as exploration and development continues, however, the amount of shale gas that is ultimately produced will depend on resource characteristics, technology improvements, prices, access to resources and environmental constraints.

## Natural Gas Drilling and Production Trends in Canada and the U.S.

Figure 4: US Production and Drilling




Source: EIA

### United States

U.S. natural gas production averaged 1,824 Bcf/month in 2009 – a 3% increase over 2008 and a 14% increase over the previous 5-year average (2004-2008). Year-to-date production in 2010 (Jan-Apr) has averaged 1,846 Bcf/month (see Figure 4). The dramatic increase in production over the last three years has reinstated the potential for natural gas use in existing markets and emerging markets such as power generation and vehicles.

In contrast to higher production levels in 2009, the number of natural gas wells drilled declined to 46% from 32,623 in 2008 to 17,742 in 2009 making 2009 the lowest annual total since 2000 (16,940 wells) in response to lower prices.

As illustrated in figure 5, indication of U.S. production strength comes in the form of lower liquefied natural gas imports. Prior to shale gas, the U.S. viewed U.S. LNG imports as the major incremental supply source and a number of new import terminals were built bringing U.S. import capacity from 80 Bcf/month in 2005 to 400 Bcf/month in 2010. However, imports have declined from 907 Bcf in 2007 to 534 Bcf in 2009 despite a four-fold increase in import capacity. As a result, average U.S. LNG terminal operating capacity has been less than 15% since 2008 from over 60% in 2007.

### Canada

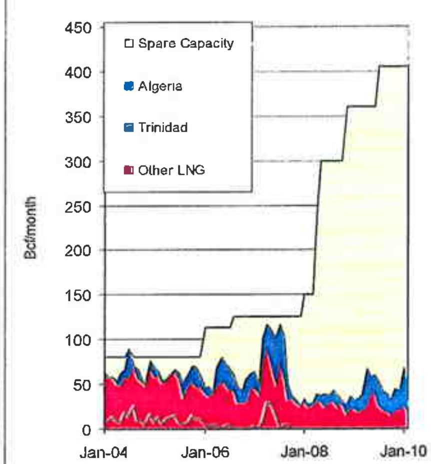
Unlike the U.S. where unconventional development is further along, Canadian natural gas production is currently more focused on conventional gas plays. In the transition to a more unconventionally focussed basin, natural gas production from the western Canadian Sedimentary Basin has declined 15% from 530 billion cubic feet per month (Bcf/month) in 2002 to 450 Bcf/month in 2010 (see Figure 6). This downward trend in production is driven largely by a 59% decline in drilling from 12,361 wells in 2008 to 5,082 wells in 2009. Drilling declines were brought about by lower natural gas commodity prices (rendering many wells uneconomic), limited conventional drilling targets and the depressed economic climate which reduced the industrial appetite for natural gas.

In 2010, industry activity remains below the high witnessed since 2002 but signs of recovery are evident in 2010 with the monthly well drilling over the Jan-May period averaging 481 wells, well above the lows in September 2009 of 181 wells. Production has begun to recover slowly in response to higher drilling and further albeit modest, recovery is expected in 2011 and 2012 driven by favourable prices and royalty changes.

With respect to unconventional development in Canada, producers have long been successfully extracting large quantities of tight gas and CBM from Alberta and BC. Canadian tight gas production is an estimated 4.6 Bcf/d (30% of Canadian production) with CBM coming in at 0.8 Bcf/d (8% of Canadian production)[2].

Shale development is less mature in Canada with the first commercial shale play in northeast BC just in 2007. Since 2007 interest in Canadian shale gas has continued with development of the Montney hybrid-shale and tight-gas play seeing growth in production from 0.15 Bcf/d in 2008 to an expected 1.5 Bcf/d in 2012[3]. The Horn River Basin shale saw about three dozen wells producing

Figure 5: LNG Imports and Import Capacity



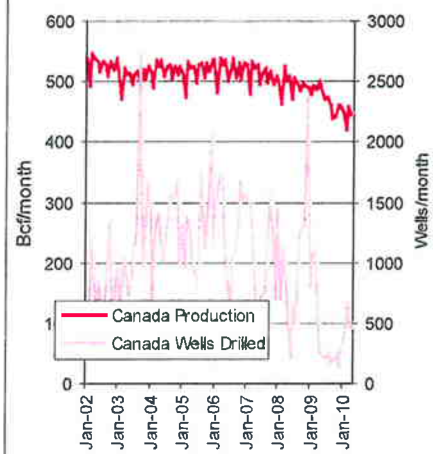

Sources: EIA, NEB

gas by year-end of 2009 and the NEB expects production to increase to 0.5 Bcf/d by 2012. Since Horn River shale gas is approximately 12% carbon dioxide (CO2), there have been a number of proposed projects for carbon capture and sequestration (CCS) facilities associated with its production.

In eastern Canada, several wells were drilled in the Utica Shale in Quebec, including a few horizontal wells, with variable but encouraging results. Finally, the Frederick Brook Member of the Horton Bluff Group in New Brunswick had significant gas flow from a vertical well.

Looking past 2012, shale production will be led by the Montney and Horn River in British Columbia which energy analysts have compared to North America's most prolific shale play – the Barnett Shale in Texas. Land sales in BC have reflected the optimism as is evident by the record prices paid for shale bearing land parcels both in 2009 and 2010.

Figure 6: Canadian Production and Drilling




Source: NEB, CAODC

## Market Implications of Increased Gas Supply

***Prices:*** As illustrated in Figure 7, the price of natural gas in North America has undergone periods of highs and lows due to a number of events including weather extremes, rising and falling crude oil prices, market transformation (shale gas) and economic recession. Most recently, the price of natural gas has declined from a peak of over 45 cents per cubic meter in mid-2008 to between 15-20 cents per cubic meter – levels not witnessed in 10 years that were brought about by both the boom in shale gas production and general slowing in demand due to recessionary impacts.

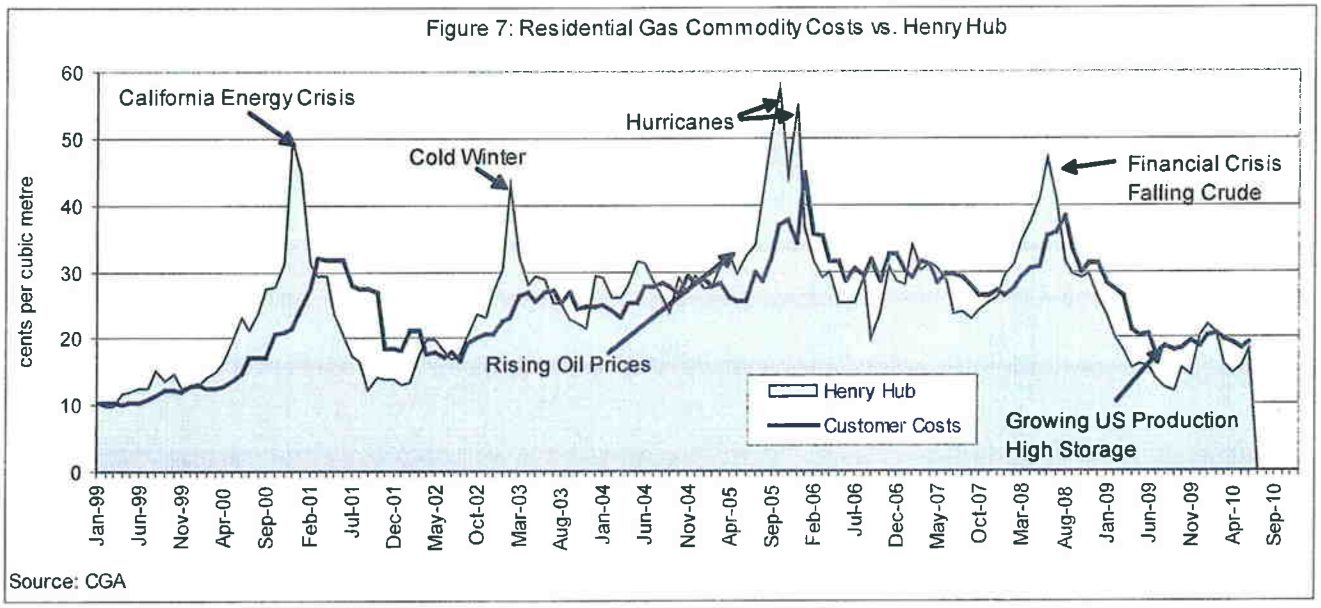
The commodity price of natural gas going forward will be a deciding factor on the level of future natural gas development. It appears that even in the wake of lower prices, producers continued to actively develope their shale gas plays while development of conventional was delayed until prices recover or development costs come down. The conclusion being that shale plays have replaced conventional plays as the new low cost producing basins in North America – a function of production efficiencies and higher extraction rates.

***Pipelines and Gas Flows***: In a similar fashion as CBM and tight gas before it, expanding shale production areas across Canada and the U.S. has prompted a number of pipeline project initiatives that are beginning to change long-standing natural gas flow patterns and routes.

In Canada, unconventional gas supply from the northeast BC region has spurred a number of pipeline projects that traverse both the traditional eastern route from BC into Alberta but also the western route to Kitimat BC where the proposed Kitimat LNG export facility is scheduled to commence operation in 2014.

The dedicated-east pipelines are led by TransCanada Pipelines[4] including the *Groundbirch Pipeline* from the *Montney shale* and the *Horn River Pipeline Project* from the Horn River shale. The dedicated-west pipeline is the Kitimat to Summit Lake Pipeline that would carry northeast BC gas to the Kitimat terminal where it would then be liquefied and exported to Asian natural gas markets.

[2] NEB, short term deliverability report, 2010.
[3] NEB, short-term deliverability report 2010.




In the U.S., the first region that witnessed significant shale related pipeline development was the U.S. Gulf Coast where some of the most advanced shale basins are situated. Significant pipeline capacity has been built out of the regions, primarily to the Florida and east markets to fuel new natural gas fired electricity generators. In addition to the Gulf Coast, the region which holds the single greatest potential to augment future North American natural gas flows is the Marcellus shale basin.

The Marcellus shale gas is found in much of Pennsylvania and West Virginia, southern New York State, eastern Ohio, western New Jersey and western Maryland. Penn State University has estimated that recoverable reserves from Marcellus are nearly 500 trillion cubic feet. Production from Marcellus is expected to be a significant and estimates range from between 2-6 Bcfd in the next decade . If Marcellus production increases as forecast, it will impact flows of natural gas to Ontario and the U.S. Northeast from their traditional supply regions in western Canada and the U.S. Gulf Coast. Already, the Marcellus shale has initiated several pipeline proposals that would connect Marcellus gas to the southern region of Ontario where it could be connected to the existing pipeline system and stored in Ontario's large underground facilities or sent directly to market.

[4]The combined value of the two pipelines is $600 million. http://www.transcanada.com/news/2009_news/20090226.html

## Conclusions

North American natural gas supply is diversifying mainly due to additional volumes from unconventional in tight, coalbed methane and shale bearing gas areas. The shift is the result of advancements in drilling and production that have improved the economics of unconventional gas resources.

Forecasts suggest unconventional gas will account for one third of total North American supply by the year 2030 from less than 10% in 2000 led by increases in shale gas production.

Canada is well positioned to increase its share of renewable natural gas and unconventional gas production backstopped by sizable resource potential in both the western Canadian sedimentary basin and eastern Canada as far as the Maritimes.

Ultimately, the success of unconventional development of North American natural gas supply is contingent on the interplay of technology, resource development cost and practices, and natural gas commodity prices.

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# 8

PUB/MH I-31

**Subject:** Tab 4: Financial Results & Forecast
**Reference:** Schedule 4.3.0 Extraprovincial Revenue

**Please extend the schedule including the years 1999/00 through 2006/07 and indicate the average exchange rate used, average energy rate per kW.h and amount of exchange dollars included in US revenue for each the years.**

**ANSWER:**

| | 1999/00 Actual | 2000/01 Actual | 2001/02 Actual | 2002/03 Actual | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual |
|---|---|---|---|---|---|---|---|
| Canadian | 90,233 | 109,275 | 92,615 | 84,143 | 53,601 | 78,255 | 172,938 |
| U.S. | 286,337 | 370,397 | 495,278 | 379,287 | 297,394 | 475,243 | 654,083 |
| | 376,570 | 479,673 | 587,893 | 463,430 | 350,994 | 553,499 | 827,021 |
| Average Exchange Rate | 1.17 | 1.1723 | 1.5665 | 1.5445 | 1.3491 | 1.2732 | 1.1893 |
| Average Price/MWh | 34.26 | 39.09 | 49.02 | 48.93 | 49.91 | 50.51 | 51.94 |
| U.S. Revenue in US$ | 242,343 | 312,074 | 325,724 | 254,560 | 217,368 | 362,164 | 537,903 |

| | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|---|
| Canadian | 85,440 | 110,062 | 131,363 | 87,037 | 68,499 | 49,618 |
| U.S. | 506,985 | 514,909 | 491,283 | 327,426 | 314,968 | 504,577 |
| | 592,426 | 624,971 | 622,646 | 414,463 | 383,467 | 554,195 |
| Average Exchange Rate | 1.1352 | 1.0256 | 1.1345 | 1.1176 | 1.07 | 1.09 |
| Average Price/MWh | 50.85 | 48.87 | 51.63 | 43.58 | 51.81 | 70.53 |
| U.S. Revenue in US$ | 432,814 | 482,512 | 427,771 | 291,297 | 276,449 | 462,915 |

# 9

**PUB/MH II-191**

**Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data**

**a) Please provide a summary tabulation of MH's 2008/09 and 2009/10 monthly export sales as defined by:**

| NEB | | | | | | SEP | | |
|---|---|---|---|---|---|---|---|---|
| Firm | | Interruptible | | Import | | Peak | Shoulder | Off-Peak |
| GWh | ¢/KWh | GWh | ¢/KWh | GWh | ¢/KWh | ¢/KWh | ¢/KWh | ¢/KWh |
| 2008/09 | | | | | | | | |
| Permit No. | | | | | | | | |
| 2009/10 | | | | | | | | |
| Permit No. | | | | | | | | |

**ANSWER:**

Please see tables below for NEB and SEP data.

| 2008/09 | SEP | | |
|---|---|---|---|
| | Peak | Shoulder | Off-Peak |
| | ¢/KWh | ¢/KWh | ¢/KWh |
| April | 7.547 | 6.092 | 3.579 |
| May | 6.799 | 5.085 | 2.695 |
| June | 7.142 | 4.772 | 2.286 |
| July | 9.591 | 4.976 | 1.626 |
| August | 9.335 | 5.161 | 1.408 |
| September | 6.246 | 3.992 | 1.181 |
| October | 5.578 | 3.873 | 1.788 |
| November | 6.912 | 4.709 | 2.760 |
| December | 8.004 | 4.933 | 3.495 |
| January | 8.391 | 5.639 | 3.678 |
| February | 5.733 | 4.143 | 2.486 |
| March | 4.762 | 3.467 | 2.339 |
| 2009/10 | | | |
| April | 3.633 | 2.665 | 1.740 |
| May | 3.166 | 2.762 | 1.329 |
| June | 2.966 | 2.188 | 0.868 |
| July | 3.329 | 2.382 | 0.937 |
| August | 3.248 | 2.012 | 0.755 |
| September | 2.630 | 1.884 | 0.625 |
| October | 2.559 | 1.878 | 0.837 |
| November | 3.521 | 2.590 | 1.574 |
| December | 3.758 | 2.720 | 1.851 |
| January | 4.916 | 3.470 | 2.295 |
| February | 5.356 | 3.966 | 2.583 |
| March | 4.345 | 3.306 | 2.336 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Apr-08 | 144 | 17,554 | 1,331,013 | 75.82 | | | | | | |
| | 155 | 21,063 | 1,081,235 | 51.33 | | | | | | |
| | 224 | 175,438 | 9,140,552 | 52.10 | | | | | | |
| | 259 | 523 | 33,718 | 64.47 | | | | | | |
| | 269 | | | | 674,057 | 38,710,758 | 57.43 | | | |
| | | | | | | | | 498 | 56,930 | 114.32 |
| May-08 | 35 | 81,724 | 3,401,427 | 41.62 | | | | | | |
| | 144 | 17,600 | 1,282,846 | 72.89 | | | | | | |
| | 155 | 21,120 | 1,087,816 | 51.51 | | | | | | |
| | 224 | 175,500 | 9,220,917 | 52.54 | | | | | | |
| | 259 | 396 | 28,906 | 72.99 | | | | | | |
| | 269 | | | | 699,599 | 31,370,396 | 44.84 | | | |
| | | | | | | | | 500 | 47,713 | 95.43 |
| Jun-08 | 33 | 19,490 | 697,220 | 35.77 | | | | | | |
| | 34 | 14,617 | 522,897 | 35.77 | | | | | | |
| | 35 | 73,902 | 3,379,308 | 45.73 | | | | | | |
| | 144 | 16,407 | 1,233,972 | 75.21 | | | | | | |
| | 155 | 19,866 | 1,068,185 | 53.77 | | | | | | |
| | 224 | 162,001 | 8,977,792 | 55.42 | | | | | | |
| | 259 | 475 | 31,630 | 66.59 | | | | | | |
| | 269 | | | | 494,860 | 24,520,507 | 49.55 | | | |
| | | | | | | | | 4,897 | 744,598 | 152.05 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Jul-08 | 33 | 70,400 | 2,535,990 | 36.02 | | | | | | |
| | 34 | 52,800 | 1,901,992 | 36.02 | | | | | | |
| | 35 | 96,900 | 5,633,561 | 58.14 | | | | | | |
| | 144 | 18,380 | 1,375,994 | 74.86 | | | | | | |
| | 155 | 22,055 | 1,157,066 | 52.46 | | | | | | |
| | 224 | 183,686 | 9,799,722 | 53.35 | | | | | | |
| | 259 | 366 | 28,736 | 78.51 | | | | | | |
| | 269 | | | | 799,886 | 37,260,178 | 46.58 | | | |
| | | | | | | | | 1,106 | 134,304 | 121.43 |
| Aug-08 | 33 | 67,200 | 2,507,804 | 37.32 | | | | | | |
| | 34 | 50,400 | 1,880,853 | 37.32 | | | | | | |
| | 35 | 108,900 | 4,898,303 | 44.98 | | | | | | |
| | 144 | 16,788 | 1,314,433 | 78.30 | | | | | | |
| | 155 | 20,160 | 1,125,657 | 55.84 | | | | | | |
| | 224 | 168,000 | 9,583,228 | 57.04 | | | | | | |
| | 259 | 383 | 29,647 | 77.41 | | | | | | |
| | 269 | | | | 859,734 | 34,817,392 | 40.50 | | | |
| | | | | | | | | 2,356 | 254,097 | 107.85 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Sep-08 | 33 | 19,210 | 705,067 | 36.70 | | | | | | |
| | 34 | 14,407 | 536,282 | 37.22 | | | | | | |
| | 35 | 106,950 | 3,584,400 | 33.51 | | | | | | |
| | 144 | 17,428 | 1,354,954 | 77.75 | | | | | | |
| | 155 | 21,120 | 1,159,702 | 54.91 | | | | | | |
| | 224 | 173,640 | 9,762,961 | 56.23 | | | | | | |
| | 259 | 357 | 28,666 | 80.30 | | | | | | |
| | 269 | | | | 795,097 | 23,433,570 | 29.47 | | | |
| | | | | | | | | 492 | 52,767 | 107.25 |
| Oct-08 | 35 | 111,600 | 4,153,724 | 0.04 | | | | | | |
| | 144 | 18,400 | 1,633,552 | 0.09 | | | | | | |
| | 155 | 22,080 | 1,373,405 | 0.06 | | | | | | |
| | 224 | 184,000 | 11,635,701 | 0.06 | | | | | | |
| | 259 | 384 | 29,688 | 0.08 | | | | | | |
| | 269 | | | | 694,487 | 24,144,820 | 34.77 | | | |
| | | | | | | | | 1,199 | 82,222 | 68.58 |
| Nov-08 | 144 | 15,994 | 1,465,977 | 91.66 | | | | | | |
| | 155 | 19,200 | 1,265,540 | 65.91 | | | | | | |
| | 224 | 160,000 | 10,819,982 | 67.62 | | | | | | |
| | 259 | 642 | 39,378 | 61.34 | | | | | | |
| | 269 | | | | 614,926 | 24,241,549 | 39.42 | | | |
| | | | | | | | | 300 | 8,925 | 29.75 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Dec-08 | 144 | 18,381 | 1,642,812 | 89.38 | | | | | | |
| | 155 | 22,080 | 1,382,550 | 62.62 | | | | | | |
| | 224 | 158,320 | 10,639,551 | 67.20 | | | | | | |
| | 259 | 854 | 52,411 | 61.37 | | | | | | |
| | 269 | | | | 197,415 | 13,641,499 | 69.10 | | | |
| | | | | | | | | 48,883 | 1,682,653 | 34.42 |
| Jan-09 | 144 | 17,600 | 1,595,364 | 90.65 | | | | | | |
| | 155 | 21,117 | 1,352,687 | 64.06 | | | | | | |
| | 224 | 161,779 | 10,888,078 | 67.30 | | | | | | |
| | 259 | 1,192 | 68,796 | 57.71 | | | | | | |
| | 269 | | | | 123,830 | 7,442,112 | 60.10 | | | |
| | | | | | | | | 61,915 | 2,559,045 | 41.33 |
| Feb-09 | 144 | 16,000 | 1,506,201 | 94.14 | | | | | | |
| | 155 | 19,200 | 1,301,862 | 67.81 | | | | | | |
| | 224 | 156,110 | 10,944,203 | 70.11 | | | | | | |
| | 259 | 833 | 50,946 | 61.16 | | | | | | |
| | 269 | | | | 173,600 | 8,571,553 | 49.38 | | | |
| | | | | | | | | 6,749 | 344,517 | 51.05 |
| Mar-09 | 144 | 17,568 | 1,623,272 | 92.40 | | | | | | |
| | 155 | 21,120 | 1,378,863 | 65.29 | | | | | | |
| | 224 | 172,308 | 11,550,659 | 67.03 | | | | | | |
| | 259 | 833 | 50,946 | 61.16 | | | | | | |
| | 269 | | | | 194,748 | 8,194,807 | 42.08 | | | |
| | | | | | | | | 19,095 | 719,180 | 37.66 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Apr-09 | 144 | 17,541 | 1,536,031 | 87.57 | | | | | | |
| | 155 | 21,049 | 1,303,354 | 61.92 | | | | | | |
| | 224 | 175,418 | 11,070,661 | 63.11 | | | | | | |
| | 259 | 639 | 40,227 | 62.95 | | | | | | |
| | 269 | | | | 466,954 | 11,164,381 | 23.91 | | | |
| | | | | | | | | 500 | 61,317 | 122.63 |
| May-09 | 33 | 47,217 | 629,505 | 13.33 | | | | | | |
| | 34 | 35,430 | 469,493 | 13.25 | | | | | | |
| | 35 | 52,174 | 1,046,940 | 20.07 | | | | | | |
| | 144 | 16,588 | 1,445,711 | 87.15 | | | | | | |
| | 155 | 9,928 | 587,038 | 59.13 | | | | | | |
| | 224 | 287,476 | 11,604,608 | 40.37 | | | | | | |
| | 259 | 481 | 35,977 | 74.80 | | | | | | |
| | 269 | | | | 448,634 | 10,411,481 | 23.21 | | | |
| | | | | | | | | 813 | 33,550 | 41.27 |
| Jun-09 | 33 | 86,711 | 2,357,030 | 27.18 | | | | | | |
| | 34 | 6,588 | 1,805,106 | 274.00 | | | | | | |
| | 35 | 7,200 | 308,462 | 42.84 | | | | | | |
| | 144 | 17,600 | 1,617,138 | 91.88 | | | | | | |
| | 155 | 16,078 | 758,261 | 47.16 | | | | | | |
| | 224 | 303,767 | 13,019,826 | 42.86 | | | | | | |
| | 259 | 461 | 35,204 | 76.36 | | | | | | |
| | 269 | | | | 434,693 | 11,286,387 | 25.96 | | | |
| | | | | | | | | 1,851 | 32,292 | 17.45 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Jul-09 | 33 | 119,319 | 2,928,700 | 24.55 | | | | | | |
| | 34 | 89,632 | 2,197,587 | 24.52 | | | | | | |
| | 35 | 2,250 | 58,679 | 26.08 | | | | | | |
| | 144 | 18,400 | 1,562,504 | 84.92 | | | | | | |
| | 155 | 14,731 | 680,137 | 46.17 | | | | | | |
| | 224 | 358,969 | 12,602,626 | 35.11 | | | | | | |
| | 259 | 394 | 32,545 | 82.60 | | | | | | |
| | 269 | | | | 521,232 | 10,303,089 | 19.77 | 1,851 | 160,870 | 86.91 |
| Aug-09 | 33 | 132,126 | 3,214,448 | 24.33 | | | | | | |
| | 34 | 9,063 | 2,410,700 | 265.99 | | | | | | |
| | 35 | 1,650 | 43,737 | 26.51 | | | | | | |
| | 144 | 16,800 | 1,463,074 | 87.09 | | | | | | |
| | 155 | 13,800 | 653,061 | 47.32 | | | | | | |
| | 224 | 362,391 | 12,705,102 | 35.06 | | | | | | |
| | 259 | 425 | 33,766 | 79.45 | | | | | | |
| | 269 | | | | 512,427 | 11,298,361 | 22.05 | 495 | 34,035 | 68.76 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Sep-09 | 33 | 28,367 | 961,127 | 33.88 | | | | | | |
| | 34 | 21,352 | 724,358 | 33.92 | | | | | | |
| | 144 | 16,888 | 1,437,114 | 85.10 | | | | | | |
| | 155 | 15,644 | 682,116 | 43.60 | | | | | | |
| | 224 | 176,859 | 9,980,692 | 56.43 | | | | | | |
| | 259 | 320 | 29,621 | 92.57 | | | | | | |
| | 269 | | | | 721,192 | 13,904,731 | 19.28 | | | |
| | | | | | | | | 437 | 41,672 | 95.36 |
| Oct-09 | 35 | 77,706 | 2,358,613 | 30.35 | | | | | | |
| | 144 | 17,358 | 1,480,174 | 85.27 | | | | | | |
| | 155 | 10,416 | 596,508 | 57.27 | | | | | | |
| | 224 | 173,876 | 10,162,359 | 58.45 | | | | | | |
| | 269 | | | | 866,924 | 20,512,094 | 23.66 | | | |
| | 345 | 527 | 37,820 | 71.76 | | | | | | |
| | | | | | | | | 0 | 0 | 0.00 |
| Nov-09 | 144 | 16,800 | 1,410,645 | 83.97 | | | | | | |
| | 155 | 10,080 | 572,268 | 56.77 | | | | | | |
| | 224 | 168,000 | 9,756,683 | 58.08 | | | | | | |
| | 269 | | | | 652,817 | 15,208,111 | 23.30 | | | |
| | 345 | 503 | 36,853 | 73.27 | | | | | | |
| | | | | | | | | 12,766 | 291,376 | 22.82 |

| Month | NEB Permit No. | FIRM | | | INTERRUPTIBLE | | | IMPORT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh | MWh | Revenue (CAN$) | ¢/KWh |
| Dec-09 | 144 | 18,337 | 1,510,887 | 82.40 | | | | | | |
| | 155 | 11,002 | 602,185 | 54.73 | | | | | | |
| | 224 | 178,620 | 10,045,274 | 56.24 | | | | | | |
| | 269 | | | | 180,369 | 7,233,228 | 40.10 | | | |
| | 345 | 785 | 50,708 | 64.60 | | | | | | |
| | | | | | | | | 96,983 | 2,446,474 | 25.23 |
| Jan-10 | 144 | 16,800 | 1,420,784 | 84.57 | | | | | | |
| | 155 | 10,080 | 576,381 | 57.18 | | | | | | |
| | 224 | 157,869 | 9,449,930 | 59.86 | | | | | | |
| | 269 | | | | 294,690 | 12,031,863 | 40.83 | | | |
| | 345 | 1,004 | 61,779 | 61.53 | | | | | | |
| | | | | | | | | 78,020 | 1,928,233 | 24.71 |
| Feb-10 | 144 | 1,600 | 1,344,224 | 840.14 | | | | | | |
| | 155 | 9,600 | 550,946 | 57.39 | | | | | | |
| | 224 | 159,086 | 9,384,649 | 58.99 | | | | | | |
| | 269 | | | | 238,998 | 9,492,286 | 39.72 | | | |
| | 345 | 948 | 58,242 | 61.44 | | | | | | |
| | | | | | | | | 43,325 | 1,060,605 | 24.48 |
| Mar-10 | 144 | 18,389 | 1,469,898 | 79.93 | | | | | | |
| | 155 | 11,033 | 585,515 | 53.07 | | | | | | |
| | 224 | 183,900 | 9,935,043 | 54.02 | | | | | | |
| | 269 | | | | 496,047 | 14,153,374 | 28.53 | | | |
| | 345 | 684 | 46,670 | 68.23 | | | | | | |
| | | | | | | | | 1,107 | 15,147 | 13.68 |

PUB/MH II-191

**Reference:** **Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data**

**b)** **Please provide a summary tabulation of MH's 2008/09 and 2009/10 monthly NEB sales (by Permit No.) defining:**

- **Volume (GWh).**
- **Unit Price (¢ per KWh)**
- **Revenue ($M)**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH II-191(a) for NEB filings by Permit No.

**PUB/MH II-191**

**Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data**

**c) Please provide MH's updated forecasts for 2010/11 with respect to:**

- **5x16 export prices**
- **2x16 export prices**
- **7x5 export prices**

**ANSWER:**

Manitoba Hydro respectfully declines to provide this information as it is confidential and commercially sensitive.

**PUB/MH II-191**

**Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data**

**d) Please confirm that MH currently does file on a specific contract basis, data on capacity (MW/$/kVA) and energy (GWh/¢/KWh).**

**ANSWER:**

Manitoba Hydro files with the NEB on an export permit number basis. Capacity and energy dollars are reported on a combined basis.

# 10

**PUB/MH/PRE-ASK-14**

**Reference: PUB/MH II-3 (a) & (b) OM&A Cost per Customer**

**Please file a schedule in similar format to PUB/MH II-3(a) providing a comparison between IFF10 and IFF09. Please recast (b) based on IFF10.**

**ANSWER:**

Please see the following tables for a comparison of the OM&A cost per customer for the years 2009 through 2017 (IFF10 to IFF09). In the second table, the impact of accounting changes is separately disclosed.

The initial increase in cost per customer is attributable to OM&A cost increases as a result of early adoption of accounting changes and revised estimates for Wuskwatim. Over time, these increases are offset by an increased customer forecast.

| | Actual | | Forecast - IFF10 | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| OM&A expense 'electric only' ($ millions) | 364 | 378 | 398 | 402 | 414 | 422 | 430 | 439 | 448 |
| # of Customers | 527,472 | 532,359 | 538,002 | 543,574 | 548,659 | 553,369 | 558,059 | 562,706 | 567,338 |
| OM&A (electric only) per customer (in dollars) | 691 | 709 | 739 | 739 | 754 | 762 | 771 | 780 | 789 |

| | Actual | Forecast - IFF09 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| OM&A expense 'electric only' ($ millions) | 364 | 372 | 380 | 403 | 411 | 420 | 428 | 437 | 445 |
| # of Customers | 527,472 | 531,804 | 536,267 | 540,756 | 545,215 | 549,623 | 553,968 | 558,286 | 562,580 |
| OM&A (electric only) per customer (in dollars) | 691 | 699 | 708 | 746 | 755 | 764 | 773 | 782 | 792 |

| | Change | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| OM&A (electric only) per customer (in dollars) | - | 11 | 31 | (6) | (0) | (1) | (2) | (2) | (2) |

| (in millions of dollars) | Actual 2009 | 2010 | Forecast - IFF10 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| OM&A expense 'electric only' | 354 | 365 | 367 | 375 | 387 | 395 | 403 | 412 | 421 |
| CICA Accounting Changes: | | | | | | | | | |
| Reduction in Stores Overhead Capitalized | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Reduction in Intangible Assets Capitalized | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Reduction in Administrative & General Overhead Capitalized | - | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| IFRS Accounting Changes | - | - | 18 | 14 | 14 | 14 | 14 | 14 | 14 |
| Total OM&A expense 'electric only' | 364 | 378 | 398 | 402 | 414 | 422 | 430 | 439 | 448 |
| # of Customers | 527,472 | 532,359 | 538,002 | 543,574 | 548,659 | 553,369 | 558,059 | 562,706 | 567,338 |
| OM&A (electric only) per customer (in dollars) | 691 | 709 | 739 | 739 | 754 | 762 | 771 | 780 | 789 |

| (in millions of dollars) | Actual 2009 | Forecast - IFF09 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| OM&A expense 'electric only' | 354 | 361 | 369 | 377 | 385 | 394 | 402 | 411 | 419 |
| CICA Accounting Changes: | | | | | | | | | |
| Reduction in Stores Overhead Capitalized | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Reduction in Intangible Assets Capitalized | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Reduction in Administrative & General Overhead Capitalized | - | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| IFRS Accounting Changes | - | - | - | 15 | 15 | 15 | 15 | 15 | 15 |
| Total OM&A expense 'electric only' | 364 | 372 | 380 | 403 | 411 | 420 | 428 | 437 | 445 |
| # of Customers | 527,472 | 531,804 | 536,267 | 540,756 | 545,215 | 549,623 | 553,968 | 558,286 | 562,580 |
| OM&A (electric only) per customer (in dollars) | 691 | 699 | 708 | 746 | 755 | 764 | 773 | 782 | 792 |

| (in millions of dollars) | 2009 | 2010 | 2011 | 2012 | Change 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| OM&A (electric only) per customer (in dollars) | - | 11 | 31 | (6) | (0) | (1) | (2) | (2) | (2) |

# 11

**PUB/MH/PRE-ASK-15**

**Reference: PUB/MH II-23 (a) EFT**

**a) Please update PUB/MH II-23 (a) to incorporate actual 2009/10 and updated 2010/11 and 2011/12 results.**

**ANSWER:**

The following schedule updates PUB/MH I-23(a) to incorporate actual results for 2009/10. Please note that 2008/09 has also been restated to reflect changes in accounting standards for intangible assets. In addition, IFF10 OM&A targets have been adjusted to reflect the provision for accounting changes.

**MANITOBA HYDRO**
**OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT**

(000's)

| | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | Fiscal 2004/05-2008/09 Compounded Annual Growth | 2009/10 Actual | 2010/11 Forecast | 2011/12 Forecast | Fiscal 2008/09-2011/12 Compounded Growtl % Inc/(Dec) |
|---|---|---|---|---|---|---|---|---|---|---|
| *Labour* | | | | | | | | | | |
| Wages, Salaries | $ 320,808 | $ 332,257 | $ 344,701 | $ 359,249 | $ 380,031 | 4.3 | $ 407,988 | $ 415,215 | $ 424,765 | 3.8 |
| Overtime | 33,842 | 38,032 | 38,896 | 41,781 | 45,890 | 7.9 | 50,307 | 48,061 | 49,166 | 2.3 |
| Employee Benefits | 68,442 | 70,184 | 73,636 | 76,807 | 83,671 | 5.2 | 82,674 | 93,035 | 95,175 | 4.4 |
| **Subtotal - Labour and Benefits** | **423,093** | **440,473** | **457,233** | **477,838** | **509,592** | 4.8 | **540,968** | **556,311** | **569,106** | 3.8 |
| EFTs (Straight Time + Overtime) | 5,885 | 5,999 | 6,007 | 6,090 | 6,312 | 1.8 | 6,465 | 6,704 | 6,704 | 2.0 |
| **Labour & Benefits per EFT** | **72** | **73** | **76** | **78** | **81** | 2.9 | **84** | **83** | **85** | 1.7 |
| Employee Safety & Training | 5,275 | 3,686 | 3,487 | 3,646 | 4,145 | (5.8) | 4,623 | 4,747 | 4,856 | 5.4 |
| Travel | 23,534 | 26,212 | 27,729 | 28,331 | 31,812 | 7.8 | 32,435 | 32,963 | 33,721 | 2.0 |
| Motor Vehicle | 17,726 | 19,380 | 19,731 | 22,423 | 24,126 | 8.0 | 24,281 | 23,114 | 23,646 | (0.7) |
| Materials & Tools | 23,893 | 26,046 | 25,414 | 27,824 | 29,345 | 5.3 | 26,897 | 26,178 | 26,780 | (3.0) |
| Consulting & Professional Fees | 7,269 | 7,229 | 8,498 | 7,503 | 9,704 | 7.5 | 14,814 | 10,904 | 11,155 | 4.8 |
| Construction & Maintenance Services | 13,345 | 13,700 | 13,711 | 15,938 | 18,378 | 8.3 | 20,109 | 21,785 | 22,286 | 6.6 |
| Building & Property Services | 21,031 | 22,973 | 24,697 | 25,740 | 28,947 | 8.3 | 22,931 | 20,671 | 21,146 | (9.9) |
| Equipment Maintenance & Rentals | 9,546 | 10,720 | 11,606 | 11,719 | 13,029 | 8.1 | 14,379 | 13,858 | 14,177 | 2.9 |
| Consumer Services | 4,203 | 4,301 | 4,316 | 4,651 | 5,284 | 5.9 | 5,798 | 5,683 | 5,814 | 3.2 |
| Computer Services | 3,959 | 4,293 | 2,622 | 1,131 | 858 | (31.8) | 983 | 696 | 712 | (6.0) |
| Collection Costs | 5,161 | 6,790 | 7,218 | 5,256 | 5,019 | (0.7) | 4,599 | 4,542 | 4,646 | (2.5) |
| Customer & Public Relations | 5,223 | 5,585 | 6,493 | 6,665 | 6,901 | 7.2 | 8,155 | 6,014 | 6,152 | (3.8) |
| Sponsored Memberships | 1,149 | 1,012 | 1,187 | 1,192 | 1,465 | 6.3 | 1,325 | 1,267 | 1,296 | (4.0) |
| Office & Administration | 15,447 | 15,902 | 14,939 | 14,427 | 14,652 | (1.3) | 15,320 | 15,703 | 15,857 | 2.7 |
| Communication Systems | 1,844 | 1,447 | 1,866 | 1,353 | 1,449 | (5.8) | 1,772 | 1,603 | 1,640 | 4.2 |
| Research & Development Costs | 3,685 | 2,874 | 3,251 | 2,979 | 3,059 | (4.6) | 3,952 | 4,110 | 4,205 | 11.2 |
| Miscellaneous Expense | 2,470 | 2,811 | 2,422 | 3,292 | 903 | (22.2) | 1,190 | 1,087 | 1,112 | 7.2 |
| Contingency Planning | - | - | - | - | - | | - | 3,361 | 2,491 | |
| Operating Expense Recovery | (18,105) | (19,205) | (20,570) | (23,314) | (21,519) | 4.4 | (21,580) | (16,497) | (16,670) | (8.2) |
| **Total Costs** | 569,749 | 596,229 | 615,849 | 638,594 | 687,149 | 4.8 | 722,951 | 738,099 | 754,129 | 3.1 |
| Capital Order Activities | (157,730) | (170,458) | (176,992) | (192,338) | (203,077) | 6.5 | (224,298) | (235,040) | (239,741) | 5.7 |
| CICA Accounting Changes* | - | - | - | - | 5,000 | | 9,000 | 7,000 | 7,000 | 11.9 |
| Provision for Accounting Changes | - | - | - | - | - | | - | 18,000 | 13,500 | |
| Capitalized Overhead | (58,174) | (62,028) | (61,887) | (67,289) | (65,743) | 3.1 | (69,151) | (69,021) | (70,447) | 2.3 |
| Operating and Administration Charged to Centra | (55,232) | (53,085) | (53,505) | (56,270) | (59,042) | 1.7 | (60,951) | (61,343) | (62,570) | 2.0 |
| **OM&A Attributable to Electric Operations** | **$ 298,613** | **$ 310,658** | **$ 323,465** | **$ 322,697** | **$ 364,287** | 5.1 | **$ 377,551** | **$ 397,695** | **$ 401,870** | 3.3 |

* Other CICA Accounting Changes totalling $4.6 million in 2008/09 and $4.0 million in 2009/10 & future years are embedded within the Total Costs

**PUB/MH/PRE-ASK-15**

**Reference: PUB/MH II-23 (a) EFT**

**b) Please provide the Compounded Annual Growth for the 2004/05 to 2009/10 and 2009/10 to 2011/12.**

**ANSWER:**

Please see the following schedule which incorporates actual results for 2009/10. Please note that 2008/09 has been restated to reflect changes in accounting standards for intangible assets. In addition, IFF10 OM&A targets have been adjusted to reflect the provision for accounting changes.

**MANITOBA HYDRO**
**OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT**

(000's)

| | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Actual | Fiscal 2004/05-2008/09 Compounded Annual Growth | 2010/11 Forecast | 2011/12 Forecast | Fiscal 2008/09-2011/12 Compounded Growtl % Inc/(Dec) |
|---|---|---|---|---|---|---|---|---|---|---|
| *Labour* | | | | | | | | | | |
| Wages, Salaries | $ 320,808 | $ 332,257 | $ 344,701 | $ 359,249 | $ 380,031 | $ 407,988 | 4.9 | $ 415,215 | $ 424,765 | 2.0 |
| Overtime | 33,842 | 38,032 | 38,896 | 41,781 | 45,890 | 50,307 | 8.3 | 48,061 | 49,166 | (1.1) |
| Employee Benefits | 68,442 | 70,184 | 73,636 | 76,807 | 83,671 | 82,674 | 3.9 | 93,035 | 95,175 | 7.3 |
| **Subtotal - Labour and Benefits** | 423,093 | 440,473 | 457,233 | 477,838 | 509,592 | 540,968 | 5.0 | 556,311 | 569,106 | 2.6 |
| EFTs (Straight Time + Overtime) | 5,885 | 5,999 | 6,007 | 6,090 | 6,312 | 6,465 | 1.9 | 6,704 | 6,704 | 1.8 |
| **Labour & Benefits per EFT** | 72 | 73 | 76 | 78 | 81 | 84 | 3.1 | 83 | 85 | 0.7 |
| Employee Safety & Training | 5,275 | 3,686 | 3,487 | 3,646 | 4,145 | 4,623 | (2.6) | 4,747 | 4,856 | 2.5 |
| Travel | 23,534 | 26,212 | 27,729 | 28,331 | 31,812 | 32,435 | 6.6 | 32,963 | 33,721 | 2.0 |
| Motor Vehicle | 17,726 | 19,380 | 19,731 | 22,423 | 24,126 | 24,281 | 6.5 | 23,114 | 23,646 | (1.3) |
| Materials & Tools | 23,893 | 26,046 | 25,414 | 27,824 | 29,345 | 26,897 | 2.4 | 26,178 | 26,780 | (0.2) |
| Consulting & Professional Fees | 7,269 | 7,229 | 8,498 | 7,503 | 9,704 | 14,814 | 15.3 | 10,904 | 11,155 | (13.2) |
| Construction & Maintenance Services | 13,345 | 13,700 | 13,711 | 15,938 | 18,378 | 20,109 | 8.5 | 21,785 | 22,286 | 5.3 |
| Building & Property Services | 21,031 | 22,973 | 24,697 | 25,740 | 28,947 | 22,931 | 1.7 | 20,671 | 21,146 | (4.0) |
| Equipment Maintenance & Rentals | 9,546 | 10,720 | 11,606 | 11,719 | 13,029 | 14,379 | 8.5 | 13,858 | 14,177 | (0.7) |
| Consumer Services | 4,203 | 4,301 | 4,316 | 4,651 | 5,284 | 5,798 | 6.6 | 5,683 | 5,814 | 0.1 |
| Computer Services | 3,959 | 4,293 | 2,622 | 1,131 | 858 | 983 | (24.3) | 696 | 712 | (14.9) |
| Collection Costs | 5,161 | 6,790 | 7,218 | 5,256 | 5,019 | 4,599 | (2.3) | 4,542 | 4,646 | 0.5 |
| Customer & Public Relations | 5,223 | 5,585 | 6,493 | 6,665 | 6,901 | 8,155 | 9.3 | 6,014 | 6,152 | (13.1) |
| Sponsored Memberships | 1,149 | 1,012 | 1,187 | 1,192 | 1,465 | 1,325 | 2.9 | 1,267 | 1,296 | (1.1) |
| Office & Administration | 15,447 | 15,902 | 14,939 | 14,427 | 14,652 | 15,320 | (0.2) | 15,703 | 15,857 | 1.7 |
| Communication Systems | 1,844 | 1,447 | 1,866 | 1,353 | 1,449 | 1,772 | (0.8) | 1,603 | 1,640 | (3.8) |
| Research & Development Costs | 3,685 | 2,874 | 3,251 | 2,979 | 3,059 | 3,952 | 1.4 | 4,110 | 4,205 | 3.2 |
| Miscellaneous Expense | 2,470 | 2,811 | 2,422 | 3,292 | 903 | 1,190 | (13.6) | 1,087 | 1,112 | (3.3) |
| Contingency Planning | - | - | - | - | - | - | | 3,361 | 2,491 | |
| Operating Expense Recovery | (18,105) | (19,205) | (20,570) | (23,314) | (21,519) | (21,580) | 3.6 | (16,497) | (16,670) | (12.1) |
| **Total Costs** | 569,749 | 596,229 | 615,849 | 638,594 | 687,149 | 722,951 | 4.9 | 738,099 | 754,129 | 2.1 |
| Capital Order Activities | (157,730) | (170,458) | (176,992) | (192,338) | (203,077) | (224,298) | 7.3 | (235,040) | (239,741) | 3.4 |
| CICA Accounting Changes* | - | - | - | - | 5,000 | 9,000 | | 7,000 | 7,000 | (11.8) |
| Provision for Accounting Changes | - | - | - | - | - | - | | 18,000 | 13,500 | |
| Capitalized Overhead | (58,174) | (62,028) | (61,887) | (67,289) | (65,743) | (69,151) | 3.5 | (69,021) | (70,447) | 0.9 |
| Operating and Administration Charged to Centra | (55,232) | (53,085) | (53,505) | (56,270) | (59,042) | (60,951) | 2.0 | (61,343) | (62,570) | 1.3 |
| Adjustment per IFF10 | | | | | | | | - | - | |
| **OM&A Attributable to Electric Operations** | $ 298,613 | $ 310,658 | $ 323,465 | $ 322,697 | $ 364,287 | $ 377,551 | 4.8 | $ 397,695 | $ 401,870 | 3.2 |

* Other CICA Accounting Changes totalling $4.6 million in 2008/09 and $4.0 million in 2009/10 & future years are embedded within the Total Costs

# 12

## PUB/MH I-5 (REVISED)

**Subject:** **Tab 3: Corporate Overview**
**Reference:** **Tab 3 Staffing/ Tab 4 Appendix 4.4, Schedule 4.5.4**

c) **Please provide a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 1999/00 to 2011/12**

## ANSWER:

Please see the following tables for salary, wages and benefits information for 2003/04 through 2011/12.

Labour & Benefits includes salary, wages, overtime and benefits.

(in thousands of $)

| Labour and Benefits as a Percentage of OM&A and Domestic Revenue | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast |
|---|---|---|---|---|---|---|---|---|
| Labour and Benefits | $398,449 | $423,093 | $440,473 | $457,233 | $477,838 | $509,592 | $544,952 | $556,311 |
| Total OM&A Costs (before capitalization) | $542,660 | $569,749 | $596,229 | $615,849 | $638,594 | $685,075 | $723,701 | $738,099 |
| Labour and Benefits as a % of OM&A | 73.4% | 74.3% | 73.9% | 74.2% | 74.8% | 74.4% | 75.3% | 75.4% |
| Domestic Revenue (GCR) | $918,231 | $938,954 | $983,653 | $1,023,613 | $1,074,581 | $1,126,812 | $1,160,009 | $1,192,762 |
| Labour and Benefits as a % of GCR | 43.4% | 45.1% | 44.8% | 44.7% | 44.5% | 45.2% | 47.0% | 46.6% |

Activity charges form the basis for cost allocation to capital projects. Activity rates are built up from a number of costs including salaries, wages and benefits, meals & accommodations, transportation costs, vehicle charges etc. An estimate of the activity charges recovering labour and benefit costs is 75%. The following outlines the amount of labour and benefits capitalized through activity charges.

(in thousands of $)

| | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast |
|---|---|---|---|---|---|---|---|---|
| Capital Order Activities | ($148,769) | ($157,730) | ($170,459) | ($176,992) | ($192,338) | ($205,175) | ($231,073) | ($235,040) |
| Labour & Benefits Capitalized | ($111,577) | ($118,297) | ($127,844) | ($132,744) | ($144,254) | ($153,881) | ($173,305) | ($176,280) |

**PUB/MH II-2**

**Subject:** **Tab 3 Corporate Overview**
**Reference:** **PUB/MH I-5 (c)**

**b) Please update the response to include the % of Labour and Benefits Capitalized (based on 75% proportion of Capital Order Activity) and explain the factors that have led to the increase in the proportion of labour and benefits capitalized since 2004/05**

**ANSWER:**

The following chart provides the % of labour and benefits capitalized to total labour & benefits:

| | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|---|---|---|---|
| Labour & Benefits Capitalized | $111,577 | $118,297 | $127,844 | $132,744 | $144,254 | $153,881 | $173,305 | $176,280 | $179,806 |
| Total Labour and Benefits | $398,449 | $423,093 | $440,473 | $457,233 | $477,838 | $509,592 | $544,952 | $556,311 | $569,106 |
| % of Lab. & Ben Cap./Total | 28% | 28% | 29% | 29% | 30% | 30% | 32% | 32% | 32% |

The increase in percentage of labour and benefits capitalized over the period is related to the expanded capital program, including significant new generation/transmission projects over the same period.

# 13

## PUB/MH I-19

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **2009 Annual Report, Note 6, Page 99**

**With respect to the Construction in Progress balances outlined in note 6 to the financial statements, please provide the following:**

i. **Describe MH's policy for capitalizing Construction in Progress costs.**
ii. **Please provide a breakdown of the balances by component of capitalized costs (wages, overhead etc.) for each major Generation and Transmission project.**

## ANSWER:

i. Manitoba Hydro capitalizes all project costs related to asset additions, including direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Capital project costs are charged to Construction Work in Progress until the corresponding asset becomes available for use, at which time the transfer to in-service property plant and equipment is made, interest expense allocated to construction ceases, and depreciation and finance expense charged to operations commences.

ii. See table below for breakdown of construction in progress costs for Major New Generation & Transmission projects, as at March 31, 2009.

(in thousands of dollars)

| Major New Generation & Transmission | Component of Capitalized Costs | | | | | |
|---|---|---|---|---|---|---|
| | Wages | Overhead | Materials & Other | Interest | Contributions | Total |
| Wuskwatim - Generation | 16 | | 55 586 | 107 986 | | 163 588 |
| Wuskwatim - Transmission | 54 745 | | | | | 54 745 |
| Herblet Lake - The Pas 230kV Transmission | 6 701 | | | | | 6 701 |
| Keeyask - Generation | 11 994 | 4 841 | | 7 917 | (159 399) | (134 646) |
| Conawapa - Generation | | 14 068 | | | | 14 068 |
| Kelsey Improvements & Upgrades | | 3 456 | 232 511 | | | 235 967 |
| Kettle Improvements & Upgrades | | | 20 276 | | | 20 276 |
| Pointe du Bois Improvements & Upgrades | | | 94 118 | | | 94 118 |
| Pointe du Bois - Transmission | | | 106 021 | | | 106 021 |
| Bipole 3 | | | 25 536 | | | 25 536 |
| Riel 230/500kV Station | | | 15 681 | | | 15 681 |
| Total | 73 456 | 22 366 | 549 729 | 115 904 | (159 399) | 602 056 |

## NOTE 6 PROPERTY, PLANT AND EQUIPMENT

| | 2010 | | | 2009 | | |
|---|---|---|---|---|---|---|
| | *millions of dollars* | | | | | |
| | In service | Accumulated depreciation | Construction in progress | In service | Accumulated depreciation | Construction in progress |
| Generation | | | | | | |
| Hydraulic | 4 722 | 1 551 | 1 531 | 4 626 | 1 484 | 1 084 |
| Thermal | 510 | 259 | 6 | 519 | 262 | 4 |
| Transmission lines | 782 | 274 | 203 | 785 | 260 | 145 |
| Substations | 2 387 | 1 094 | 220 | 2 308 | 1 023 | 121 |
| Distribution | 2 998 | 1 079 | 50 | 2 853 | 1 004 | 44 |
| Other | 1 289 | 355 | 42 | 1 209 | 323 | 40 |
| | 12 688 | 4 612 | 2 052 | 12 300 | 4 356 | 1 438 |

## NOTE 7 MATERIALS AND SUPPLIES

| | 2010 | 2009 |
|---|---|---|
| | *millions of dollars* | |
| Materials and supplies | 65 | 67 |
| Natural gas inventory | 33 | 15 |
| | 98 | 82 |

**PUB/MH I-204 (REVISED)**

**Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11**

**Please provide a schedule indicating the level of capitalized OM&A and Finance Expense for each of the years 1999 through 2029.**

**ANSWER:**

| (000's) | | |
|---|---|---|
| | Capitalized OM&A * | Finance Expense allocated to Construction |
| 2003/04 | 207,593. | 31,564 |
| 2004/05 | 215,904 | 32,683 |
| 2005/06 | 232,487 | 34,496 |
| 2006/07 | 238,879 | 47,071 |
| 2007/08 | 259,627 | 60,015 |
| 2008/09 | 271,373 | 74,493 |
| 2009/10 | 299,037 | 91,505 |
| 2010/11 | 304,061 | 130,789 |
| 2011/12 | 310,188 | 137,126 |
| 2012/13 | N/A | 110,061 |
| 2013/14 | N/A | 144,108 |
| 2014/15 | N/A | 208,376 |
| 2015/16 | N/A | 306,070 |
| 2016/17 | N/A | 408,036 |
| 2017/18 | N/A | 449,275 |
| 2018/19 | N/A | 430,042 |
| 2019/20 | N/A | 365,023 |
| 2020/21 | N/A | 300,298 |
| 2021/22 | N/A | 352,971 |
| 2022/23 | N/A | 329,902 |
| 2023/24 | N/A | 159,756 |
| 2024/25 | N/A | 30,714 |
| 2025/26 | N/A | 29,672 |
| 2026/27 | N/A | 17,854 |
| 2027/28 | N/A | 22,687 |
| 2028/29 | N/A | 24,875 |

*Capitalized OM&A is specifically forecast to 2011/12. In subsequent forecasts, net OM&A is escalated at 2% with no corresponding forecast for capitalized OM&A.

# 14

**PUB/MH II-150**

**Subject:** **Tab 13 Board Directives**
**Reference:** **PUB/MH I-176 Rate Regulated Accounting; PUB/MH I-16**

c) **Please file PUB/MH I (c) dated February 20, 2009 as a document to this proceeding and indicate whether any of the adjustments to retained earnings reflected in the document are currently incorporated in IFF09. Please identify adjustments related to rate-regulated assets and liabilities.**

**ANSWER:**

Please see the attachment for PUB/MH I(c) dated February 20, 2009.

The following table summarizes the IFF08 and IFF09 adjustments:

| IFF08 | IFF09 |
|---|---|
| Includes a write-down to retained earnings of $50 million for 2009/10 for ineligible research and promotion charges re: CICA Intangible Assets Standard changes. | Includes a write-down to retained earnings of $26 million for 2009/10 for ineligible research and promotion charges re: CICA Intangible Assets Standard changes. |
| Includes a write-down to retained earnings of $59 million for 2011/12 for rate regulated assets - assuming IFRS would not have a standard for rate regulated accounting. | Assumes IFRS would have a standard for rate regulated accounting and therefore does not have an adjustment for rate regulated assets. |
| Includes a $10 million annual charge for ineligible research, promotion and indirect overhead charges not considered eligible for capitalization. | Includes an $11 million annual charge for ineligible research, promotion and indirect overhead charges not considered eligible for capitalization. |
| Includes a $15 million annual charge for reductions in capitalized overhead and general administrative expenditures. | Includes a $15 million annual charge for reductions in capitalized overhead and general administrative expenditures. |
| Includes reductions in annual amortization expense for reductions in capitalized expenditures and for retained earnings adjustments for ineligible research and promotion charges and rate regulated items. | Includes reductions in annual amortization expense for reductions in capitalized expenditures and for retained earnings adjustments for ineligible research and promotion charges and rate regulated items. |

# 15

# INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

## STATUS UPDATE REPORT as at October 31 2010

Manitoba Hydro

**Executive Summary**

Manitoba Hydro (MH) will be required to prepare financial statements in accordance with International Financial Reporting Standards (IFRS) effective for its 2012/13 fiscal year with comparative information presented for 2011/12. The 2012/13 transition year represents a one year deferral from the previous required transition year of 2011/12 and is a result of recent decisions made by the International and Canadian accounting standard setting bodies.

There are a number of differences between Canadian Generally Accepted Accounting Principles (GAAP) and IFRS that will affect the timing of when costs are recognized in MH's net income, how business transactions are recorded, and how information is presented in MH's financial statements. The transition to IFRS is expected to result in an initial increase in annual operating and administrative expense, increased volatility in net income, the recognition of additional obligations on the balance sheet, some changes to the presentation of financial statements and more extensive note disclosure. Ultimately, however, IFRS will result in improved comparability of MH's financial statements and financial performance to other energy utilities throughout the world.

MH commenced its IFRS conversion project in 2008 with the establishment of a formal project structure including a project team, steering committee and an executive sponsor. The project was divided into four phases: initial assessment & project mobilization, detailed design, solution development, and implementation. MH is managing the project internally with resources from across its business units and with assistance as necessary from external advisors. KPMG was engaged as the primary consultant on the project and to date has assisted with accounting gap analysis, identification of system and process impacts, and the interpretation of IFRS standards. MH's external auditor, Ernst & Young, has provided advice and has concurred with accounting changes that have been implemented to March 31, 2010 and has participated in discussions on various IFRS conversion issues.

In September of 2010, the International Accounting Standards Board (IASB) discontinued their project on rate-regulated accounting on the basis that this topic will require more analysis and discussion than IASB resources currently allow in consideration of other priorities. The IASB announced that it will seek future direction on this topic from their constituents in the spring of 2011. In recognition of the impact of the uncertainty around rate-regulated accounting for rate-regulated entities, in September 2010, the Canadian Accounting Standards Board (AcSB) approved an optional one year deferral on transition to IFRS for rate-regulated entities. As is the case with most other rate-regulated utilities in Canada, MH plans to adopt this deferral.

The topics in the following table have been identified as having the highest potential impact to MH:

| Topic | Issue |
|---|---|
| Rate-Regulated Accounting | - IFRS does not currently recognize rate-regulated accounting<br>- In September of 2010, the IASB discontinued their project on the accounting for Rate-regulated activities and will seek future direction on this topic from its constituents in 2011<br>- In September 2010, the AcSB approved an optional one year deferral for transition to IFRS for rate-regulated entities<br>- The Canadian Electrical Association (CEA) and the "Big 4" accounting firms plan to further discuss the recognition of rate-regulated assets and liabilities under IFRS<br>- As at March 31, 2010, MH had $296 million in net Rate-regulated assets on its balance sheet |
| Intangible Assets | - GAAP converged with IFRS effective for MH's 2009/10 financial statements<br>- The impact of this change on prior years was a cumulative reduction to retained earnings of $37 million related to the write-off of ineligible research and promotional related expenditures<br>- The annual net income impact of this change is immaterial considering the offsetting impacts of increases in operating expense and decreases in amortization |
| Property, Plant & Equipment (PP&E) | - The IASB has approved an exemption for rate-regulated entities to carry forward existing PP&E balances as of the transition date<br>- IFRS is more rigorous in identifying separate components for depreciation<br>- IFRS requires gains and losses on asset retirements to be charged to net income in the year incurred and does not allow, in the absence of an obligation, future removal costs to be included in depreciation rates<br>- IFRS requires a liability to be recorded for "constructive asset retirement obligations"<br>- Under IFRS, customer contributions are recognized as revenue, either immediately or over the life of the asset |

| | |
|---|---|
| Capitalization of Overhead Costs | - IFRS specifically states that administration and other general overhead costs are not eligible for capitalization<br>- To date, MH adjustments with respect to discontinuing the capitalization of overhead costs total approximately $30 million annually |
| Pension Costs | - IFRS does not permit the deferral of experience gains and losses for calculating expected fund returns<br>- First time adopters have an option to adjust unrecognized experience gains or losses to equity<br>- Proposed Exposure Draft to recognize all actuarial gains and losses in Other Comprehensive Income |
| Employee Benefits | - IFRS requires the estimated obligation for the unvested portion of accumulating benefits to be recognized over the period of service<br>- Benefits for past service must be expensed over the vesting period |

IFRSs will continue to evolve both before and after the transition date. In the interim, MH will continue to review its accounting policies and design its systems and processes with sufficient flexibility to be able to capture required transactional data and meet the accounting and reporting requirements of the Corporation.

The next steps in the project will focus on advancing all topics from the solution development to the implementation phase and ensuring that key systems and processes, meet the accounting and reporting requirements for the 2011/12 comparative year and forward. This work will be performed with the assistance of MH's consultants.

## 1.0 Introduction

The Canadian Accounting Standards Board (AcSB) had previously declared January 1, 2011 as the date for Canadian publicly accountable enterprises to commence using International Financial Reporting Standards (IFRS) as a replacement for Canadian Generally Accepted Accounting Principles (GAAP). The Public Sector Accounting Board (PSAB) also confirmed in October of 2009 that public-sector enterprises with self-sustaining commercial-type operations such as Manitoba Hydro (MH) will be required to follow IFRS. However, as a result of the uncertainty by the IASB regarding the acceptability of rate-regulated accounting, the AcSB approved an optional one year deferral of transition for rate-regulated entities in September 2010. As such, the transition to IFRS will be reflected in MH's financial statements for the fiscal year 2012/13, along with comparative information for the 2011/12 fiscal year.

Although IFRS and GAAP are both principles-based, there are a number of differences between IFRS and GAAP that can result in differences in the timing of when costs are recognized. IFRS contains a number of accounting policy choices and it is for individual entities to determine the most appropriate accounting policies that reflect their own facts and circumstances. As an underlying principle, MH is interpreting and applying IFRS in a manner that recognizes the long term nature of its business and the need, to the extent possible, to preserve the fundamental principles of intergenerational equity amongst the present and future energy consumers of the Province. This objective underlies the preliminary accounting policy decisions discussed in this report.

The overall impacts from conversion to IFRS can be summarized in the following three categories:

a) **Transitional Adjustments**

The transition to IFRS will likely result in adjustments to opening retained earnings as IFRS generally requires retrospective application. Such adjustments are somewhat less onerous for rate-regulated entities due to an exemption that allows rate-regulated entities to carry-forward the historical cost of its property, plant & equipment upon transition to IFRS. Therefore, MH is not expecting that the adjustment to opening retained earnings will be significant for its property, plant & equipment assets.

b) **Ongoing differences**

There will be ongoing differences in the timing of recognition of certain transactions. In addition, IFRS may give rise to more volatility in earnings due to differences in the accounting for items such as expected returns on pension fund assets, past service employee benefits, and the recognition of gains and losses on property, plant & equipment retirements.

c) **Project Costs**

The initial conversion to IFRS will result in project costs associated with internal resources, external consulting, assurance requirements, and information systems. MH is estimating the project costs to be approximately $5.0 million.

## 4.0 Key Areas of Impact

The main topic areas of impact to MH upon conversion to IFRS include:

1. Rate-Regulated Accounting
2. Goodwill & Intangible Assets
3. Property, Plant & Equipment
4. Capitalization of Overhead Costs
5. Pension Costs
6. Employee Benefits
7. Financial Instruments
8. Leases
9. Customer Contributions
10. IFRS 1 - Initial Adoption of IFRS

The following sections provide an overview of each of these main topic areas.

## 4.1 Rate-Regulated Accounting

The following sections describe rate-regulated accounting under GAAP and IFRS.

### 4.1.1 Rate-Regulated Accounting under GAAP

MH recognizes the impact of rate-regulation by applying various accounting policies that allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. This practice is commonly referred to as rate-regulated accounting. In the absence of rate-regulated accounting, these costs or credits may otherwise have been included in the determination of net income in the year incurred.

Effective January 1, 2009, GAAP was revised to remove a temporary exemption that permitted the recognition of assets and liabilities resulting from rate regulation. In the absence of specific guidance under GAAP, rate-regulated entities in Canada are permitted to reference and apply Accounting Standards Codification 980, "Regulatory Operations" (formerly FAS 71), issued by the US Financial Accounting Standards Board (FASB), which allows for the recognition of rate-regulated assets and liabilities under the following circumstances:

a) The enterprise's rates for regulated services or products are established by or subject to approval by an independent, third-party regulator;
b) The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services; and

c) It is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers.

Pursuant to a practice allowed by Canadian GAAP, MH has relied on this standard to maintain its current accounting treatment for rate-regulated assets and liabilities for 2009/10 and will continue to do so until transition to IFRS.

**4.1.2 IASB Exposure Draft on Rate-regulated Activities**

Currently, IFRS does not include a specific standard that explicitly recognizes the economic effects of rate regulation. While IFRS does not preclude the recognition of regulatory assets and liabilities, it requires that an asset or liability must meet the existing framework for recognition. The application of the IFRS framework in other countries has not typically resulted in the recognition of regulatory assets and liabilities.

The absence of specific IFRS guidance for rate-regulated accounting has been a significant concern of the Canadian utility industry since the AcSB decision to transition to IFRS was announced. This issue was on the agenda of both the International Financial Reporting Interpretation Committee (IFRIC) and the IASB in 2008. The IASB added this project to its agenda in December 2008 because of concerns that differences of views would emerge in practice about whether it was appropriate for entities to recognize assets and liabilities arising from rate regulation and because of the ongoing requests for guidance on this issue.

The IASB issued an Exposure Draft (ED), Rate-regulated Activities, on July 23, 2009. The proposed standard allowed for assets and liabilities that arise from rate-regulated activities (within the scope of the ED) to be recognized under IFRS.

The responses to the ED were submitted in November 2009 and were mixed in terms of those supporting and opposing the proposed standard. MH provided commentary to the IASB on the ED and also provided input into the Canadian Electrical Association, Canadian Gas Association and Canadian Energy Pipeline Association joint response.

The IASB met to discuss the comments received and to provide direction on the Rate-regulated Activities ED on February 17, 2010. At this meeting it was tentatively confirmed that entities subject to rate regulation should be allowed an additional exemption to IFRS to carry forward existing balances of PP&E and intangibles at transition to IFRS. However, no decision as to the future direction of the ED was reached. Rather, because of the diversity in responses to the ED and the concern that diversity may arise in practice, IASB staff were directed to conduct further analysis and research and to present their findings at a future meeting.

On May 6, 2010, the IASB approved an amendment to IFRS 1 (First-time Adoption of IFRS) to allow entities with rate-regulated activities to use the carrying amount of their property, plant and equipment and intangible asset balances from their previous GAAP as deemed cost upon transition to IFRS. These balances may include amounts that would not be permitted for capitalisation under IAS 16 Property, Plant and Equipment, IAS 23 Borrowing Costs and IAS 38 Intangible Assets.

At their July 19 - 23, 2010 meetings, IASB members remained divided on whether to develop a rate-regulated activities standard. IASB staff presented four potential paths for consideration by the IASB:

- Fast track the finalization of the comprehensive project (Exposure Draft)
- Issue an Interim standard
- Issue an amendment to IFRS1
- The continuation of the research, analysis and deliberations on this issue as time and resources permit acknowledging the existing guidance and current practice that has developed in the countries that apply IFRSs

IASB members selected the fourth option.

**4.1.3 Recent Developments**

On July 23, 2010, the AcSB determined that entities with rate-regulated activities will require additional time to prepare themselves and the users of their financial statements for conversion to IFRSs. The AcSB thus, issued an Exposure Draft that proposed that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the Canadian GAAP standards (Part V of the CICA handbook) for an additional two years. Comments received by the AcSB supported the need for a deferral for transition for rate-regulated entities. Both MH and the CEA responded to the ACSB in support of the deferral.

On September 8, 2010, the AcSB approved a one year deferral for transition to IFRS for entities subject to rate regulation, indicating that due to the uncertainty of the timing of the resolution of this issue, they did not want to prolong the continued use of Canadian GAAP standards beyond an additional year. As is the case with most other rate-regulated utilities in Canada, MH plans to adopt this deferral.

On September 16, 2010, IASB members further reviewed the issue of rate-regulated accounting and concluded that members were clearly divided in terms of those supporting and those opposing the recognition of rate-regulated assets and liabilities. The IASB thus decided to discontinue the project on rate-regulated accounting on the basis that this topic will require more analysis and discussion than IASB resources currently allow in consideration of other priorities. The IASB will include in its public consultation in the spring of 2011 on its future agenda a request for views on what form a future project might take, if any, to address the impact of rate regulation. Potential paths forward for this topic as proposed by the IASB include:

- A disclosure only standard
- An interim standard
- A medium term project focused on the effects of rate regulation, or
- A comprehensive project on intangible assets

As a result of recent developments, the CEA and the "Big 4" accounting firms have agreed to review and assess the extent to which the actions of rate regulators result in assets and liabilities that can be recognized in accordance with existing IFRSs. The objective is to obtain resolution to this issue by early 2011.

#### 4.1.4 Rate-Regulated Accounts

The following table summarizes MH's rate-regulated assets and liabilities as at March 31, 2010:

**Table 4.1 Summary of Rate-Regulated Accounts**
**At March 31, 2010**
(In millions of dollars)

| Item | Electric | Gas | Consolidated |
|---|---|---|---|
| Power Smart Programs * | $168 | $32 | $200 |
| Site Restoration Costs | 35 | 2 | 37 |
| Deferred Taxes | - | 35 | 35 |
| Acquisition Costs | 23 | - | 23 |
| Purchased Gas Variance Accounts | - | (3) | (3) |
| Regulatory Costs | - | 4 | 4 |
| | $226 | $70 | $296 |

* During the 2009/10 period, MH reclassified $168 million of electric related unamortized

Power Smart Program expenditures from deferred charges to Rate-Regulated Assets as a result of the convergence of Canadian GAAP with IFRS for intangible assets. Gas Power Smart Program expenditures were previously classified as Rate-Regulated Assets.

Should it be concluded that rate-regulated assets and liabilities cannot be recognized under IFRS, the balances in the aforementioned accounts will be adjusted to retained earnings and future expenditures will be expensed as incurred.

## 4.2 Goodwill & Intangible Assets

Effective for MH's 2009/10 fiscal year, GAAP was converged with IFRS for the recognition and measurement of Goodwill & Intangible Assets (GAAP section 3064). The new standard required retrospective application for the 2008/09 fiscal year.

### 4.2.1 Goodwill

MH acquired two major utility operations - Centra Gas in July 1999 and Winnipeg Hydro in September 2002. As a result of these acquisitions, MH has recorded Goodwill in the amount of $108 million which has remained unchanged since March 31, 2003. In accordance with GAAP, goodwill is not amortized; it is tested for impairment on an annual basis unless all of the following criteria have been met:

a) The assets and liabilities that make up the reporting unit have not changed significantly since the most recent fair value determination;
b) The most recent fair value determination resulted in an amount that exceeded the carrying amount of the reporting unit by a substantial margin; and
c) Based on an analysis of events that have occurred and circumstances that have changed since the most recent fair value determination, the likelihood that a current fair value determination would be less than the current carrying amount of the reporting unit is remote.

The goodwill accounting requirements under GAAP and IFRS are converged, however, GAAP uses a different impairment testing model from IFRS. IFRS determines an impairment loss as the excess of the carrying amount above the recoverable amount of the cash generating unit to which the goodwill is allocated, rather than the difference between carrying amount and fair value of the reporting unit's goodwill as required for GAAP.

Under IFRS, irrespective of whether there is any indication of impairment, an entity is required to test goodwill acquired in a business combination for impairment annually. The IFRS impairment testing model is applied at the cash generating unit level as compared to the GAAP model which is applied at the reporting unit level. In addition, IFRS allows for a reversal of an impairment loss for long lived assets, but it does not permit an impairment reversal for goodwill.

MH will incorporate these changes into an annual impairment test for the goodwill resulting from the acquisition of Centra Gas and Winnipeg Hydro. MH does not expect that the application of this impairment test upon transition to IFRS will result in any impairments.

**Transitional Requirements (IFRS 1)**

In general, the requirements are applied retrospectively when an entity adopts IFRS. This means that MH would need to consider its past acquisitions and ensure they have been accounted for in accordance with the business combination standard under IFRS, which could impact the calculation of goodwill. Under IFRS 1, a first-time adopter has the optional exemption to not retroactively restate any business combinations that occurred prior to the date of transition to IFRS. MH expects that it will take the exemption and not restate any business combinations.

**4.2.2 Intangible Assets**

The new Canadian standard includes criteria for an expenditure to qualify for recognition as an intangible asset and stipulates that research related expenditures are to be expensed in the period incurred. Under GAAP and IFRS, an expenditure is recognized as an intangible asset only if it meets one of the following "identifiable" criteria:

a) Is separable (i.e., is capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, asset or liability); or
b) Arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

Examples of identifiable intangibles are franchise rights, patents, and licenses.

In addition to the "identifiable" requirement, an entity must demonstrate its ability to control and obtain the future economic benefits from the intangible asset. For internally generated intangible assets, the new section 3064 also requires the following "research" related activities to be expensed as incurred:

a) Activities aimed at obtaining new knowledge;
b) The search for, evaluation and final selection of, applications of research findings or other knowledge;
c) The search for alternatives for materials, devices, products, processes, systems or services; and
d) The formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

Activities incurred after the selection of a chosen alternative for the project are eligible for capitalization with the exception of:

- Selling, administrative and other general overhead expenditures unless this expenditure can be directly attributed to preparing the asset for use;
- Identified inefficiencies and initial operating losses incurred before the asset achieves planned performance; and
- Expenditures on training staff to operate the asset.

The following sections summarize the impact of the convergence of GAAP with IFRS for MH with respect to intangible assets.

**Power Smart Programs (Demand Side Management-DSM)**

MH previously recognized electric DSM program expenditures as deferred costs and natural gas DSM program expenditures as rate-regulated assets.

MH determines the feasibility of a number of electric DSM programs and only implements those which meet specific criteria for achieving cash inflows in excess of the costs of that program. MH's electric DSM programs are a distinct and identifiable aspect of its operations that result in additional cash inflows to the company from the additional export market sales made available by the electricity conserved by domestic customers. MH assessed these programs to determine if such activities met the recognition requirements for an intangible asset under the new standard. Although these programs result in distinct and identifiable cash flows, the assessment determined that electric DSM activities do not meet the new intangible asset recognition requirements as these activities are not capable of being separated and transferred to another entity. As a result, MH reclassified unamortized electric related DSM charges to rate-regulated assets consistent with gas related DSM charges.

MH's natural gas DSM programs reduce energy costs for customers. Any decrease in natural gas volumes from DSM programs result in an overall reduction to the total commodity requirements for Manitoba customers and does not provide MH with additional cash inflows and thus, does not meet the requirements for recognition as an intangible asset.

The new standard 3064 and IFRS specifically identifies research, selling/promotion and indirect expenditures as ineligible costs for capitalization as an intangible asset. New DSM programs typically include research activities as well as promotional activities to introduce the DSM programs. To be consistent with the accounting for intangible assets, MH will expense general research and promotional activities for electric & natural gas DSM programs.

The cumulative retained earnings adjustment associated with the April 1, 2008 DSM balance for ineligible research and promotion charges was approximately $5 million for electric related DSM charges and $1 million for gas related DSM charges. Annual charges for these activities are now expensed in the period incurred.

**Planning Studies**

To comply with GAAP and IFRS, MH also reviewed its planning study expenditures and has separated the expenditures into two categories:

a) Next generation and transmission studies; and
b) Emerging energy studies (i.e. wind studies to identify potential sites, hybrid electric vehicles).

The studies for next generation and transmission plant meet the criteria for recognition as an asset, but because such expenditures are intended to ultimately result in the construction of a tangible plant asset, deferral as an intangible asset is not appropriate. Therefore, these expenditures will be recognized as tangible construction in progress (CWIP) assets at the point in time when there is reasonable assurance that a commitment to construction will be made. Expenditures incurred prior to this point will be expensed in the period incurred.

Planning studies for emerging energies result in the accumulation of information and /or research data that enables MH to assess the impacts of energy options on its operations. Although emerging energy studies are necessary, the information generated from such studies does not normally result in the creation of separate or identifiable intangible assets and thus, does not meet the criteria for recognition as an asset. Therefore the costs associated with emerging energy activities will be expensed in the period incurred. The cumulative retained earnings adjustment associated with the April 1, 2008 planning studies balance for ineligible charges was approximately $25 million.

**Information Technology - Application Development**

MH reviewed its computer system application development process and concluded that, for the most part, expenditures of this nature met the requirements for recognition as intangible assets. However, research and planning related activities involving the need for a new system (software / hardware) or the research and feasibility analysis of alternative solutions should be expensed in the period incurred.

The cumulative retained earnings adjustment associated with the April 1, 2008 Application Development Projects balance for ineligible charges was approximately $5 million.

**Presentation and Disclosure**

GAAP and IFRS emphasize that intangible assets are separate and identifiable stand alone assets and as such, should be presented separately on the balance sheet rather than being classified in PP&E. Upon adoption of section 3064, MH reclassified (April 1, 2008 balances, net of accumulated amortization) $103 million of Computer Software development and $37 million of Easements from Property, Plant & Equipment to a separate category titled Goodwill and Intangible Assets.

### 4.2.3 Summary of Impacts

The following tables summarize the actual April 1, 2008 retained earnings adjustments with respect to the retrospective application of the new standard and the impact to net income for 2009/10 amounts:

**Table 4.2.2 Summary of Transitional Adjustments to Intangible Assets - Charge to April 1, 2008 Retained Earnings**
(In millions of dollars)

| Item | Electric | Gas | Consolidated |
|---|---|---|---|
| Demand Side Management - Research and Promotion | $4.8 | $1.2 | $6.0 |
| Planning Studies | 24.6 | - | 24.6 |
| IT Application Development - Research | 3.8 | 1.0 | 4.8 |
| Other | 1.2 | - | 1.2 |
| **Decrease to Retained Earnings** | **$34.4** | **$2.2** | **$36.6** |

**Table 4.2.3 Summary of Net Income Impacts from Intangible Assets - 2009/10**
(In millions of dollars)

| Item | Electric | Gas | Consolidated |
|---|---|---|---|
| Demand Side Management - Research and Promotion | ($1.0) | ($0.8) | ($1.8) |
| Planning Studies | (2.0) | - | (2.0) |
| IT Application Development - Research | (0.6) | - | (0.6) |
| Other | (0.2) | | (0.2) |
| **Consolidated Amortization Offsets** | **5.4** | **0.3** | **5.7** |
| **Net Income Impact** | **$1.6** | **($0.5)** | **$1.1** |

The annual impacts to net income related to the changes in the standard for intangible assets reflects offsets for reductions in amortization and will vary in the future according to the degree of annual spending for these items.

**4.4 Capitalization of Overhead Costs**

Under GAAP, MH has historically applied a full cost accounting methodology. Tangible and intangible assets are stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs, and interest applied at the average cost of debt. Overhead costs allocated to capital include support staff (Finance, Human Resources, Information Technology, Corporate, Legal, etc.), management time, training, depreciation, interest, and facility related charges. This approach recognizes that MH is both a capital and operating company and thus, maintains integrated resources in order to sustain all aspects of its operations.

IFRS requires that PP&E and intangible items that qualify for recognition as an asset shall be measured at cost which includes direct costs, such as materials, and all overhead costs that can be directly attributable to capital projects and intangible assets. IFRS identifies costs that are not eligible for capitalization such as the following:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including costs of advertising and promotional activities);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
d) Administration and other general overhead costs

Based on a review of its existing cost capitalization practices, and considering industry trends to move away from full cost accounting, MH has eliminated, or is planning to eliminate, the following cost components from its capitalized overhead under GAAP (totaling $30 million annually through to the end of fiscal 2011):

**Reduction to Costs Capitalized in fiscal 2008/09:**

| | |
|---|---|
| Interest and Facilities Overhead on Stores | **$5.0 million** |

**Reduction to Costs Capitalized in fiscal 2009/10:**

| | |
|---|---|
| Executive Costs from the Overhead Pool | $2.0 million |
| Property Taxes on Facilities | $2.0 million |
| | **$4.0 million** |

**Planned Reduction to Costs Capitalized in fiscal 2010/11:**

| | |
|---|---|
| Interest on Common Assets (Facilities & Equipment) | $12.0 million |
| General and Administrative Departmental Costs | $5.0 million |
| Interest on motor vehicles | $4.0 million |
| | **$21.0 million** |

There is little specific IFRS guidance to assist with the interpretation and application of the capitalization requirements under IFRS. Manitoba Hydro is of the view that costs currently being capitalized have a strong causal relationship to capital projects or programs and it is therefore appropriate to continue to capitalize these costs. In order to demonstrate this relationship, MH is reviewing its capitalization methodology, including the cost components and activities currently being capitalized, as well as the processes in place to charge these costs to capital projects. This review will be completed in late 2010.

If a sufficient causal relationship is not found between certain costs and the related capital activities, these costs may not be eligible for capitalization under IFRS. As well, where it is found that the process used to charge costs to capital projects is not sufficiently aligned with their causal relationship to capital projects, internal charging processes may have to be modified. Any further costs that are deemed not to be eligible for capitalization under IFRS will either have to be expensed as incurred or could be deferred as a regulatory asset should the recognition of regulatory assets ultimately be allowed under IFRS.

All work necessary to allow for the accounting of capitalized costs in an IFRS compliant manner will be completed for implementation in fiscal 2011/12 to allow for comparative year reporting. Any substantial system and process changes that are deemed to be appropriate to optimize related internal accounting processes will be developed and implemented for fiscal 2012/13.

**Transitional Requirements (IFRS 1)**

The IASB allows rate-regulated entities to carry over the net book value of PP&E upon transition to IFRS and thus, any existing capitalized costs included in PP&E may form part of the deemed costs of PP&E on transition. Therefore, no retroactive adjustment is required to adjust the differences in capitalized overhead costs.

**4.5 Pension Costs**

There are a number of differences that will result from adopting IFRS for defined benefit pension plans. The components that make up the cost of defined benefit plans may be recognized on a different basis under IFRS than under existing GAAP.

**4.5.1 Return on Plan Assets**

The expected return on plan assets forms part of the annual pension expense. GAAP currently allows the expected return on plan assets to be estimated based on either fair value or a market-related value (moving average not exceeding a period of five years). MH uses market-related values to estimate the expected return on plan assets and to apply experience gains and losses in the corridor calculation. A market-related value approach reduces volatility of actuarial gains and losses on the expected annual return on plan assets and subsequent amortization of balances outside the corridor, therefore, reducing volatility on annual pension expense.

Under IFRS, the expected return on plan assets must be estimated using the fair value of assets at the beginning of the period. The use of fair value increases the volatility of the expected return on plan assets and will be highly dependant on the investment performance of the market during each reporting period.

**4.5.2 Actuarial Gains and Losses**

Under GAAP, companies have a policy choice in recording actuarial gains and losses. They can be recorded in income immediately, or amortized to income using the corridor method which accumulates gains and losses within a range (10% of the value of the fund assets or obligation, whichever is greater) and amortizes to pension expense any excess cumulative balance outside the range. Under IFRS, companies will have an additional policy choice that permits recording actuarial gains and losses immediately to Other Comprehensive Income (OCI) without any charge to net income of the period.

As of the date of this report, MH is in the process of assessing available policy options which include recording actuarial gains and losses immediately to OCI or continueing to use the corridor calculation. The assessment will also take into consideration a recent IASB Exposure Draft that requires the recording of annual actuarial gains and losses immediately to OCI; eliminating all other options for the recognition of these amounts. Should this Exposure draft be approved in 2011, MH will adopt this method of recognizing actuarial gains and losses.

**4.5.3 Past Service Costs**

GAAP allows past service costs associated with plan improvements/amendments to be recognized over the average remaining service life of the employee group. MH has implemented pension plan improvements that contain both vested and non-vested components and is currently amortizing these improvements over the average remaining service life of the employee group.

Under IFRS, amended benefits that are fully vested must be immediately recognized into income or amortized over the vesting period if not fully vested.

**4.5.4 Transitional Requirements (IFRS 1)**

The underlying principle in IFRS 1 is that a first time adopter should prepare and present financial statements as if it had always applied IFRS. Under this requirement, pension plan balances as at the transition date would be re-measured under IFRS with an adjustment to retained earnings.

Alternatively, a first time adopter of IFRS has the option to elect to recognize all cumulative actuarial gains and losses to retained earnings. As of March 31, 2010, MH's cumulative unamortized actuarial losses amount to approximately $200 million. This transition approach would eliminate the requirement to retroactively restate pension amounts up to the transition date. As well, this approach would result in the elimination of the future amortization of these existing balances in pension expense. If this approach is adopted, the corridor method can still be applied subsequent to transition.

MH is currently assessing this transitional election with the impact of these two options depending upon the March 31, 2011 final balances of cumulative unamortized actuarial recognized as an offset in depreciation expense will now be recognized as revenue.

Under IFRS, the method for recognizing revenue related to refundable contributions would also change. The practice under Canadian GAAP excludes 100% of the refundable capital contributions from being amortized. Under IFRS, only the amount that is expected to be refunded would be excluded from the amount that is amortized into revenue.

**4.10 IFRS 1 - Initial Adoption of IFRS**

IFRS 1 requires an entity to comply with all IFRSs effective at the reporting date of the entity's first annual financial statements prepared and presented in accordance with IFRS. For MH, this would include all IFRSs in effect as of March 31, 2013. New accounting policies must be retrospectively applied (unless the relevant election is available and chosen) and adjustments made at the start of comparative period. Thus, for an entity adopting IFRS for the first time on April 1, 2012, it will be necessary to prepare and present a comparative opening balance sheet under IFRS as at April 1, 2011. In the comparative opening balance sheet, an entity must:

- Recognize all assets and liabilities that IFRS require be recognized;
- Derecognize from assets and liabilities those items for which IFRS do not permit recognition;
- Reclassify items when, in accordance with the GAAP previously followed by the entity, they would have been presented differently from how they would be in accordance with IFRS
- Apply IFRS in remeasuring all recognized assets and liabilities

The underlying principle in IFRS 1 is that a first time adopter should prepare and present financial statements as if it had always applied IFRS, i.e., retrospective adjustment of accounts; however, there are certain exemptions and/or elections to this general principle which would allow prospective application. IFRS 1 prohibits retrospective application in certain areas. Exemptions are and will continue to be included in amendments to IFRS 1.

There are IFRS 1 elections for areas including financial assets and liabilities, hedge accounting, business combinations, insurance contracts, value of PP&E, leases, employee benefits, financial instruments, decommissioning liabilities, and borrowing costs. Where applicable, MH has addressed the transitional elections it is reviewing in the various sub-sections of this report.

## 7.0 Future IFRS Changes

MH is required to prepare its first set of IFRS financial statements in accordance with the standards that are in effect as at the end of the first year of adoption of IFRS (ie; March 31, 2013). MH chooses its accounting policies based on these standards and then applies them from the beginning of the comparative period, i.e. from April 1, 2011. MH's preliminary accounting policy choices as set out in this report, should not therefore, be considered final and may continue to evolve as the IFRS standards themselves change both before and after the transition date.

The IASB has a very active agenda and a number of projects may impact MH significantly. The effective date of any IFRS amendments and new standards is usually 6-18 months after their publication date. However, the IASB considers all relevant facts including whether to allow early adoption. It is important to note that many IFRS requirements will not change between now and fiscal 2012/13. However, there are significant changes to IFRS expected to be published by 2011 which may be available to be early adopted by MH and therefore may be applied by MH as it transitions to IFRS.

# 16

AUC
Alberta Utilities Commission

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# Rule 026

## Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards

The Alberta Utilities Commission (AUC/Commission) has approved this rule on May 19, 2009.

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**Contents**

Definitions .......... 1
Application .......... 3
Guiding Principles .......... 4
Expected Regulatory Accounting Disclosure .......... 4
IFRS Initial Adoption Adjustments (IFRS 1) .......... 4
Specific Regulatory Accounting Items .......... 4
Appendix I – Guiding Principles .......... 9
**Appendix II – Notes** .......... 10

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**Definitions**

1 In this rule,

(a) "Existing Accounting Practice" means the accounting procedures and policies in use by a Utility, that have been approved by the Commission for rate-making purposes, immediately prior to the adoption of this Rule;

(b) "Existing Canadian GAAP" means the widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Accounting Standards Board;

(c) "First IFRS-Compliant GRA/GTA" means the first General Rate Application/General Tariff Application filed by a Utility which includes the Utility's IFRS Adoption Date in the forecast test period;

(d) "IAS" or "International Accounting Standards" refers to the standards issued by the International Accounting Standards Committee from 1973 to 2000, when it was replaced by the International Accounting Standards Board (IASB), and as amended or replaced by the IASB;

## Appendix I – Guiding Principles

These Guiding Principles are all equally important and are to be viewed as a collective set of principles rather than a list of individual statements.

- The methodologies used by the AUC to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. The Commission has and will retain the authority to establish Regulatory Accounting and regulatory reporting requirements and as such, IFRS requirements will not be the sole driver of regulatory requirements.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will continue to be based on historical, sound regulatory principles. Examples of these principles can be found in statutes, regulatory and court decisions and regulatory texts and include intergenerational equity, minimizing rate volatility and use of historical costs rather than fair market, or any other values.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will, in considering IFRS requirements, balance the effects on customer rates and shareholders' return. Any shifting of risk between customers and shareholders will be minimized.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will be aligned as much as possible with IFRS. In establishing any future Regulatory Accounting and regulatory reporting requirements that deviate from IFRS, the Commission will ensure that any such deviations and their impact are in the public interest.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will be universal and standardized for all utilities while still recognizing that utility-specific issues can be addressed through that utility's applications.

# Ontario Energy Board

Ontario

## EB-2008-0408

# Report of the Board

## Transition to International Financial Reporting Standards

July 28, 2009

# Appendix 2: Summary of Board Policy

## 1. Principles

1.1 The methodologies used by the Board to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. The Board has and will retain the authority to establish regulatory accounting and regulatory reporting requirements. While IFRS accounting requirements are an important consideration in determining regulatory requirements, the objective of just and reasonable rates will continue to be the primary driver of such requirements.

1.2 Future regulatory accounting and regulatory reporting requirements established by the Board will continue to be based on sound regulatory principles. These principles include fairness, minimizing intergenerational inequity and minimizing rate volatility.

1.3 Future regulatory accounting and regulatory reporting requirements established by the Board will, in taking into account IFRS requirements, balance the effects on both customers and shareholders.

1.4 Future regulatory accounting and regulatory reporting requirements established by the Board will be aligned with IFRS requirements as long as that alignment is not inconsistent with sound regulatory rate making principles.

1.5 Future regulatory accounting and regulatory reporting requirements established by the Board will be universal and standardized for all utilities, while recognizing that utility-specific issues can be addressed through a utility's applications. The Board will not require modified IFRS filing and reporting requirements for utilities that are not otherwise required to adopt IFRS for financial reporting purposes.

## Major Points of Departure between Existing Regulatory Accounting and Rate Making as Compared to IFRS

### 2. Regulatory Assets and Liabilities

2.1 The Board will continue to use deferral and variance accounts for rate making in appropriate circumstances, whether or not these accounts are recognized under IFRS.

2.2 The Board will continue to apply the existing approach in the use and establishment of deferral and variance accounts at this time. The Board may consider the review and adjustment of its existing approach when the rulings from the International Accounting Standards Board are received and the interpretation of IFRS becomes clearer.

# 17

**PUB/MH/PRE-ASK-17**

**Reference: IFRS**

**Please populate the following table to include the accounting options under IFRS, the treatment prescribed by the Ontario Energy Board and the Alberta Utility Commissions and that currently followed by MH and that proposed to be followed by MH.**

| Issue | IFRS | OEB | AUC | Manitoba Hydro (current) | Manitoba Hydro (proposed) |
|---|---|---|---|---|---|
| Regulatory Assets and Liabilities | | | | | |
| Property Plant & Equipment | | | | | |
| • Borrowing Costs | | | | | |
| • Customer Contributions | | | | | |
| • Asset reclassifications from PPE to intangible assets | | | | | |
| • Asset retirement obligations | | | | | |
| • Gains and losses on disposition of assets | | | | | |
| • Treatment of asset impairment | | | | | |
| Depreciation | | | | | |
| Inventory Valuation | | | | | |
| Financial Reporting | | | | | |
| Application Reporting | | | | | |

**ANSWER**:

Manitoba Hydro has provided its most recent update on the status of IFRS separately (Appendix 78). That document provides the most current overview of the implications of IFRS on Manitoba Hydro's financial accounting and reporting.

The following tables provide a summary of this information in tabular form along with the requested information available from the AUC and OEB. Note that the AUC and OEB directives apply to rate setting processes and do not directly apply to external financial reporting requirements.

Information provided on the OEB was derived from the OEB report "EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards" (July 28, 2009); including the November 2010 update to Appendix 2 of the report. Information provided on the AUC was derived from AUC Rule 026 (May 19, 2009).

| | **Regulatory Assets and Liabilities** |
|---|---|
| IFRS | No specific standard exists under IFRS regarding the accounting for rate regulated assets and liabilities.<br><br>Recently the Canadian Electrical Association and the "Big 4" accounting firms have agreed to review and assess the extent to which the actions of rate regulators result in assets and liabilities that can be recognized in accordance within the existing framework in IFRS. |
| MH Current | MH recognizes the impact of rate-regulation by applying various accounting policies that allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. |
| MH Proposed | MH is proposing to continue with rate-regulated accounting assuming this method of accounting is available under IFRS. In the absence of rate-regulated accounting, existing rate-regulated balances may have to be adjusted to retained earnings upon transition to IFRS and future amounts included in the determination of net income in the year incurred. |
| OEB | The OEB will continue to use deferral and variance accounts for rate making in appropriate circumstances, whether or not these accounts are recognized under IFRS.<br><br>The OEB may consider the review and adjustment of its existing approach when the rulings from the International Accounting Standards Board are received and the interpretation of IFRS becomes clearer. |
| AUC | Utilities shall maintain the existing practice of applying to the Commission for approval of any deferral accounts that may be required for the purpose of establishing Regulatory Assets and Liabilities and proposing the mechanism for their disposition. |

| | **Property Plant & Equipment - Borrowing Costs** |
|---|---|
| IFRS | As per IAS 23, para. 1 "Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. Other borrowing costs are recognized as an expense." |
| MH Current | MH's interest capitalization rate consists of the weighted average debt rate for all debt outstanding for the period, including anticipated borrowings in the upcoming fiscal year. Where debt is designated to finance a particular capital project, MH will capitalize interest to the asset based on the interest rate from that designated debt issue. MH is applying this approach for its 2010/11 fiscal year under Canadian GAAP. |
| MH Proposed | No future changes are proposed upon transition to IFRS |
| OEB | The OEB will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the OEB's published rates. Otherwise, the distributor should use the OEB's published rates. |
| AUC | Subject to subsection (ii), Utilities shall maintain the Existing Accounting Practice of including the debt and equity components of AFUDC when accounting for construction work in progress and plant in service.<br>(ii) Utilities may submit an application to the AUC requesting approval to make their Regulatory Accounting practice the same as the practice under IFRS |

| | Property Plant & Equipment - Customer Contributions |
|---|---|
| IFRS | Under IFRS, customer contributions are to be recognized as revenue; either immediately or over some future period of time. The customer contribution is recognized as revenue based upon the performance obligations of the underlying arrangement. |
| MH Current | Currently, non-refundable contributions in aid of construction are separately recorded on the balance sheet and amortized to income on a straight-line basis as a reduction to depreciation over the life of the related item of PP&E. |
| MH Proposed | MH is proposing that customer contributions be recognized as deferred revenue upon transition to IFRS where the revenue will be recognized over the life of the related plant asset. This will result in little or no impact to net income. However, classification on the income statement will change as the amortization of the contribution that was previously recognized as an offset in depreciation expense will now be recognized as revenue. |
| OEB | For regulatory reporting and rate making purposes, customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facilities to which they relate. Distributors should confirm in the introduction to their first rates application after the IFRS transition that the amortization period is being adjusted on an ongoing basis. |
| AUC | Utilities shall maintain the Existing Accounting Practice of recognizing customer contributions in their Property, Plant & Equipment accounts and including the amortization as an offset to depreciation. |

| | **Property Plant & Equipment - Asset Reclassifications from PPE to Intangible Assets** |
|---|---|
| IFRS | As per IAS 38, para. 8 "An intangible asset is an identifiable non-monetary asset without physical substance."<br>As per IAS 38, para. 4. "Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a licence or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under IAS16 Property, Plant and Equipment or as an intangible asset under this Standard, an entity uses judgment to assess which element is more significant." |
| MH Current | Upon adoption of CICA section 3064 for its March 2010 year end, MH reclassified (April 1, 2008 balances, net of accumulated amortization) $103 million of Computer Software development and $37 million of Easements from Property, Plant & Equipment to a separate category titled Goodwill and Intangible Assets. |
| MH Proposed | No future changes are proposed upon transition to IFRS. |
| OEB | Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement. |
| AUC | Utilities shall maintain the Existing Accounting Practice of recognizing intangible assets as part of their Property, Plant & Equipment accounts. |

| | Property Plant & Equipment - Asset Retirement Obligations |
|---|---|
| IFRS | As per IAS 16, para. 16 "The cost of an item of property, plant and equipment comprises:,...<br>(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period."<br><br>As per IAS37 para. 10, "A constructive obligation is an obligation that derives from an entity's actions where:<br>(a) by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and<br>(b) as a result, the entity has created a valid expectation on the part of those other parties that it will discharge those responsibilities." |
| MH Current | Under GAAP, MH has recognized AROs for the decommissioning of two thermal generating stations and a hydraulic generating station, as well as for the removal and disposal of PCB's in HVDC converter station capacitors. |
| MH Proposed | MH has reviewed its circumstances under IFRS and has preliminarily concluded that no new provisions exist pertaining to constructive obligations. MH will recognize such obligations when a commitment is made to decommission an asset and significant removal and/or remediation costs are expected to be incurred |
| OEB | Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The OEB will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement. |
| AUC | Subject to subsection (ii), Utilities shall maintain the Existing Accounting Practice regarding the treatment of asset retirement obligations and future removal and site restoration costs.<br>(ii) Utilities may, by way of application to the AUC, request approval to account for asset retirement obligations and future removal and site restoration costs in accordance with IFRS. |

| | Property Plant & Equipment - Gains and Losses on Disposition of Assets |
|---|---|
| IFRS | As per IAS 16, para. 68 "The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognised,.... Gains shall not be classified as revenue." |
| MH Current | MH currently recognizes gains and losses on the retirement of plant assets in accumulated depreciation. |
| MH Proposed | Upon transition to IFRS, MH is planning to recognize gains and losses on asset retirements to net income as they occur. |
| OEB | Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the OEB. |
| AUC | Utilities shall maintain the Existing Accounting Practice of recording gains and losses upon retirement or disposal of assets. Utilities shall identify and record any difference in accounting between the IFRS reporting requirements and these regulatory reporting requirements in a separate subsidiary accumulated depreciation account. |

| | Property Plant & Equipment - Treatment of Asset Impairment |
|---|---|
| IFRS | As per IAS 36, para 9. "An entity shall assess at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, the entity shall estimate the recoverable amount of the asset.<br>para. 60, "An impairment loss shall be recognised immediately in profit or loss, unless the asset is carried at revalued amount in accordance with another Standard." |
| MH Current | Under CGAAP, long-lived assets should be tested whenever events or changes in circumstances indicate their carrying amount may not be recoverable. MH performs an annual impairment test on its goodwill balances which have not indicated any impairment to date. |
| MH Proposed | MH does not anticipate any substantial changes to its annual impairment testing requirements. |
| OEB | Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates. |
| AUC | Utilities shall maintain the Existing Accounting Practice of having no impairment (or impairment reversal) charges included when providing or reporting financial information to the AUC. |

| | **Depreciation** |
|---|---|
| IFRS | As per IAS 16, para. 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."<br>para. 60, "The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity." |
| MH Current | MH currently depreciates its PP&E component groupings on a straight-line remaining-life basis. |
| MH Proposed | MH is reviewing its asset component groupings and will establish new groupings as necessary to comply with IFRS requirements. New depreciation rates will be established for implementation upon transition to IFRS. In conjunction with this, Manitoba Hydro proposes to eliminate the pre-collection of the cost of removing retired assets from its depreciation accounting as this concept is not allowed under IFRS. |
| OEB | Utilities should continue to use the straight line method of depreciation for regulatory accounting purposes.<br>The OEB will undertake a depreciation study for electricity distributors. Until the study is completed, electricity distributors may continue to use their existing service lives for rate setting purposes. Any electrical distributor retains the option of demonstrating, through a well-founded depreciation study, that the OEB should approve specific depreciation methodologies and rates for that distributor. |
| AUC | (i) Depreciation Rates<br>A. Subject to subsection (B), Utilities shall continue to use the depreciation rates utilized under the Existing Accounting Practice.<br>B. If the adoption of the IFRS requirements for external financial reporting results in depreciation rates that differ from Existing Accounting Practice or results in a difference in the timing of commencement of depreciation, or both, then a Utility may, by way of application to the AUC, request approval to account for regulatory depreciation in accordance with IFRS.<br>(iii) Componentization<br>A. Subject to subsection (B), with respect to componentization, Utilities shall record assets at the level of detail being reported under the Existing Accounting Practice.<br>B. If the adoption of IFRS requirements for external financial reporting results in a different level of componentization, then a Utility may, by way of application to the AUC, request approval to account for regulatory componentization in accordance with IFRS. |

| | **Inventory Valuation** |
|---|---|
| IFRS | As per IAS 2, para. 9 "Inventories shall be measured at the lower of cost and net realisable value."<br>para. 10 "The cost of inventories shall comprise all costs of purchase, costs of conversion and other costs incurred in bringing the inventories to their present location and condition."<br>para 34 "When inventories are sold, the carrying amount of those inventories shall be recognized as an expense in the period in which the related revenue is recognized." |
| MH Current | MH records inventory at its average cost. |
| MH Proposed | No future changes are proposed upon transition to IFRS. |
| OEB | The OEB does not include a reference to inventory valuation outside of a reference to Purchased Gas Variance Accounts for gas utilities. |
| AUC | AUC Rule 026 does not include a reference to inventory valuation outside of capital inventories. |

| | **Financial Reporting** |
|---|---|
| IFRS | As per IAS 1, para. 15, "Financial statements shall present fairly the financial position, financial performance and cash flows of an entity. Fair presentation requires the faithful representation of the effects of transactions, other events and conditions in accordance with the definitions and recognition criteria for assets, liabilities, income and expenses set out in the Framework. The application of IFRSs, with additional disclosure when necessary, is presumed to result in financial statements that achieve a fair presentation."<br>para. 16 "An entity whose financial statements comply with IFRSs shall make an explicit and unreserved statement of such compliance in the notes. An entity shall not describe financial statements as complying with IFRSs unless they comply with all the requirements of IFRSs." |
| MH Current | MH's audited financial statements will be presented in accordance with CGAAP for fiscal years 2010/11 and 2011/12. |
| MH Proposed | MH's audited financial statements will be presented in accordance with IFRS commencing in its fiscal 2012/13 fiscal year and forward. |
| OEB | The OEB will require all electricity distributors and gas utilities that are required to adopt IFRS by accounting standard setting bodies to report information to the OEB using modified IFRS for regulatory accounting values and IFRS for audited financial statements beginning with the year in which the electricity distributor or gas utility has chosen to adopt IFRS for financial reporting. For those few utilities not required to adopt IFRS for financial reporting, the OEB will require that they report information to the Board using the form of generally accepted accounting principles approved by their external auditors as being applicable to them as regulated utilities.<br><br>The OEB will require all electricity distributors and gas utilities to continue to report information to the OEB using Canadian GAAP until and including the fiscal year prior to the year in which the electricity distributor or gas utility, as applicable, has chosen to adopt IFRS for financial reporting. |
| AUC | Please see Appendix 2 to this response for the financial reporting requirements of the AUC per AUC 026. |

| | Application Reporting |
|---|---|
| IFRS | IFRS does not include a standard that applies to the rate application reporting of rate-regulated utilities. |
| MH Current | MH's rate application financial statements will be presented in accordance with CGAAP for fiscal years 2010/11 and 2011/12 and will reflect the transition to IFRS commencing fiscal 2012/13 and forward. |
| MH Proposed | MH is proposing that upon transition to IFRS that financial and regulatory reporting will be aligned. |
| OEB | Please see Appendix 1 for reporting requirements of Electric utilities. |
| AUC | Please see Appendix 2 to this response for the application reporting requirements of the AUC. |

**Appendix 1**

OEB Report EB-2008-0408
Transition to International Financial Reporting Standards

**Regulatory Accounting Principles to Use in Electricity Cost of service Applications**

**For Electricity Distributors Adopting IFRS January 1, 2011 for Financial Reporting Purposes**

| Year in which Application Made | Rate Year for Which Application Made (Test Year) 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| **2010** | CGAAP for H, B & T **or** CGAAP for H **and** MIFRS for B & T | | | | |
| **2011** | | CGAAP for H **and** MIFRS for H, B & T | | | |
| **2012** | | | MIFRS for H, B & T | | |
| **2013** | | | | MIFRS for H, B & T | |
| **2014** | | | | | MIFRS for H, B & T |

**For Electricity Distributors Adopting IFRS January 1, 2012 for Financial Reporting Purposes**

| Year in which Application Made | Rate Year for Which Application Made (Test Year) 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| **2010** | CGAAP for H, B & T **or** CGAAP for H, B & T and MIFRS for T **or** CGAAP for H & B and MIFRS for B & T | | | | |
| **2011** | | CGAAP for H, B & T **or** CGAAP for H and MIFRS for B & T | | | |
| **2012** | | | CGAAP for H and MIFRS for H, B & T | | |
| **2013** | | | | MIFRS for H, B & T | |
| **2014** | | | | | MIFRS for H, B & T |

**Legend:**
**H** = Historic Year financial information (last full year of actual historical information)
**B** = Bridge Year regulatory financial information
**T** = Test Year regulatory financial information

**CGAAP** - Canadian Generally Accepted Accounting Principles
**MIFRS** - International Financial Reporting Standards modified by the Ontario Energy Board for regulatory purposes consistent with the Report of the Board on Transition to IFRS, July, 2009, amended November, 2010
= Year in which both CGAAP and MIFRS information required

**Appendix 2**

Excerpt from AUC Rule 026
Accounting/Reporting standards to use for Alberta utilities

**(4)** Utilities that indicate to the Commission under subsection (2) that they will be adopting IFRS shall adhere to the following schedule

| : Fiscal Year | Year Filed | Actual / Forecast | Accounting/Reporting Standard to Use |
|---|---|---|---|
| 2009 | 2010 | Actual | Existing Accounting Practice is to be used for regulatory filings with the AUC; Existing Canadian GAAP for financial statements |
| 2010 | 2011 | Actual | Existing Accounting Practice is to be followed for regulatory filings with the AUC; Existing Canadian GAAP for financial statements |
| 2011 | 2012 | Actual | This Rule is to be followed for regulatory filings with the AUC, complete with 2010 comparatives prepared using this Rule; IFRS is to be used for financial statements, including 2010 comparatives prepared under IFRS |
| 2012 & beyond | 2013 & beyond | Actual | This Rule is to be followed for regulatory filings with the AUC; IFRS is to be followed for financial statements |
| 2009 (first year in test period) | Up to December 31, 2010 | Forecast | Existing Accounting Practice is to be used |
| 2010 (first year in test period) | Up to December 31, 2010 | Forecast | Utilities may elect to file forecasts using Existing Accounting Practice, or, this Rule commencing with either the 2010 or 2011 forecast year according to the election made in subsection 2(2) of this Rule |
| 2011 (first year in test period) & beyond | 2010 & beyond | Forecast | This Rule is to be used for forecasts filed with the AUC |

18

**PUB/MH I-36 (REVISED)**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

**a) Please re-file the schedule including the years 1999/00 through 2006/07**

**ANSWER:**

Please see schedule attached.

**MANITOBA HYDRO**
**FINANCE EXPENSE**
**PUB/ MH 1 - 36 a**

| | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|---|---|---|---|
| Interest on Short & Long-Term Debt | | | | | | | | | |
| Gross Interest | $ 489,978 | $ 485,696 | $ 492,656 | $ 496,204 | $ 500,512 | $ 468,685 | $ 475,783 | $ 492,011 | $ 553,011 |
| Provincial Guarantee Fee | 66,844 | 67,801 | 65,905 | 67,997 | 69,865 | 70,360 | 72,274 | 78,099 | 82,920 |
| Amortization of (Premiums), Discounts, and Transaction Costs | (14,375) | (9,326) | (8,802) | (8,658) | (11,054) | (11,605) | (10,498) | 2,321 | 2,276 |
| Intercompany Interest Receivable | (15,259) | (15,392) | (16,470) | (16,827) | (19,774) | (18,182) | (16,380) | (19,416) | (25,015) |
| Total Interest on Short & Long-Term Debt | 527,188 | 528,778 | 533,289 | 538,716 | 539,549 | 509,259 | 521,179 | 553,015 | 613,192 |
| Interest Earned on Sinking Fund | (43,028) | (27,656) | (30,640) | (28,535) | (30,180) | (24,920) | (24,908) | (17,585) | (10,720) |
| Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges | - | - | - | - | (52,407) | (11,359) | 8,011 | 4,398 | - |
| Interest Allocated to Construction | (31,564) | (32,683) | (34,496) | (47,071) | (60,015) | (74,493) | (91,267) | (130,789) | (137,126) |
| Corporate Allocation | (16,830) | (16,763) | (16,809) | (17,141) | (17,483) | (17,543) | (17,880) | (18,704) | (18,704) |
| Other Amortization | 17,035 | 16,166 | 17,015 | 21,170 | 21,331 | 20,116 | 21,776 | 22,204 | 21,008 |
| **Total Finance Expense** | $ 452,801 | $ 467,843 | $ 468,359 | $ 467,139 | $ 400,796 | $ 401,060 | $ 416,913 | $ 412,539 | $ 467,650 |

**PUB/MH I-36**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

**b) Please provide a schedule which compares finance expense forecasts for 2007/08 and 2008/09 presented at the 2008 GRA and explain any major variances.**

**ANSWER:**

The finance expense forecasts for 2007/08 and 2008/09 were filed for the 2008 GRA as Schedule 5.3.6. For the current Application, Schedule 4.6.0 contains actual finance expenses for 2007/08 and 2008/09, and forecasts for 2009/10, 2010/11 and 2011/12.

For the current Application, the following finance expense reclassifications were adopted:

- Amortization of FMV Write-up was reclassified to Other Amortization,
- Interest on Temporary Investments was reclassified to Gross Interest,
- An amount related to interest on loans that was classified as Other Amortization was reclassified to Gross Interest, and
- Interest charged to the Wuskwatim Power Limited Partnership has been reclassified from Intercompany Interest Receivable to Interest Allocated to Construction.

In order to provide comparability with the presentation adopted for the current Application, the following schedule outlines the forecasts for 2007/08 and 2008/09 as presented at the last GRA, the forecasts as they would have been presented with the current presentation, along with variances between this revised presentation and actuals as shown in Schedule 4.6.0.

Please see the attached schedule.

PUB/MH I - 36 (b)

**MANITOBA HYDRO**
**FINANCE EXPENSE**
($000's)

| | | 2007/08 Forecast As Filed Schedule 5.3.6 2008/09 GRA (A) | | 2007/08 Forecast Reclassified Schedule 5.3.6 2008/09 GRA (B) | | 2007/08 Actual As Filed Schedule 4.6.0 2010/11 GRA (C) | | 2007/08 Variance (B - C) | | 2008/09 Forecast As Filed Schedule 5.3.6 2008/09 GRA (D) | | 2008/09 Forecast Reclassified Schedule 5.3.6 2008/09 GRA (E) | | 2008/09 Actual As Filed Schedule 4.6.0 2010/11 GRA (F) | | 2008/09 Variance (E - F) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Interest on Short & Long-Term Debt | | | | | | | | | | | | | | | | |
| Gross Interest (Note 1) | $ | 508,656 | $ | 505,356 | $ | 500,512 | $ | 4,844 | $ | 523,543 | $ | 523,543 | $ | 468,685 | $ | 54,858 |
| Provincial Guarantee Fee | | 69,865 | | 69,865 | | 69,865 | | 0 | | 71,290 | | 71,290 | | 70,360 | | 930 |
| Amortization of (Premiums), Discounts, and Transaction Costs (Note 2) | | (8,823) | | (8,823) | | (11,054) | | 2,231 | | (9,656) | | (9,656) | | (11,605) | | 1,949 |
| Amortization of FMV Write-up | | (744) | | | | | | - | | (685) | | | | | | - |
| Interest on Temporary Investments | | (1,914) | | | | | | - | | - | | | | | | - |
| Intercompany Interest Receivable (Note 3) | | (34,086) | | (19,935) | | (19,774) | | (161) | | (52,635) | | (21,772) | | (18,182) | | (3,590) |
| Total Interest on Short & Long-Term Debt | | 532,954 | | 546,463 | | 539,549 | | 6,914 | | 531,857 | | 563,405 | | 509,259 | | 54,146 |
| Interest Earned on Sinking Fund (Note 4) | | (30,133) | | (30,133) | | (30,180) | | 47 | | (31,708) | | (31,708) | | (24,920) | | (6,788) |
| Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges (Note 5) | | (53,975) | | (53,975) | | (52,407) | | (1,568) | | (25,127) | | (25,127) | | (11,359) | | (13,768) |
| Interest Allocated to Construction (Note 6) | | (52,782) | | (66,933) | | (60,015) | | (6,918) | | (58,593) | | (89,456) | | (74,493) | | (14,963) |
| Corporate Allocation | | (17,484) | | (17,484) | | (17,483) | | (1) | | (17,542) | | (17,542) | | (17,543) | | 1 |
| Other Amortization | | 19,991 | | 20,633 | | 21,331 | | (698) | | 21,257 | | 20,572 | | 20,116 | | 456 |
| **Total Finance Expense** | $ | 398,571 | $ | 398,571 | $ | 400,796 | $ | (2,225) | $ | 420,144 | $ | 420,144 | $ | 401,060 | $ | 19,084 |

**Note 1 Gross Interest -** the favourable variances are primarily from lower than forecast interest rates on floating rate long term debt, short term debt and new fixed rate long term debt, as well as lower than forecast foreign exchange rates.

**Note 2 Amortization of (Premiums), Discounts and Transaction Costs -** the variances are due to the adoption of the financial instruments accounting standards.

**Note 3 Intercompany Interest Receivable -** the variances are primarily from lower than forecast short term interest rates on intercompany advances.

**Note 4 Interest on Sinking Fund -** the variances in 2008/09 are largely from lower sinking fund returns as a result of lower than forecast foreign exchange and interest rates.

**Note 5 Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges -** the variance in 2008/09 is primarily due to the addition of US debt series C094 that was added to the US debt portfolio in February 2008.

**Note 6 - Interest Allocated to Construction -** the variances are due to lower than forecast interest capitalization rates and lower than forecast capital expenditures.

# 19

**PUB/MH II-35**

**Subject:** **Tab 4 Financial Results & Forecast**
**Reference:** **PUB/MH I-36 (a), IFRS Status Update Report Page 26**

**b)** **Please describe how the corporation determines how much interest is allocated to construction and to specific construction projects.**

**ANSWER:**

Manitoba Hydro capitalizes all project costs related to asset additions, including engineering, direct labour, materials, contracted services, and interest applied at the average cost of debt. Capital project costs are charged to Construction Work in Progress until the corresponding asset becomes available for use, at which time the transfer to in-service property plant and equipment is made, interest expense allocated to construction ceases and depreciation begins. Manitoba Hydro capitalizes interest on all domestic, major and new generation projects except certain short-term customer service projects with construction durations averaging approximately three months or less.

Interest during construction is calculated by applying the interest capitalization rate to the actual or forecasted month-end work in progress balance of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Interest capitalized calculated by project is then aggregated to form to total interest allocated to construction.

Please see Manitoba Hydro's response to PUB/MH II-35(c) for an example as to how interest is calculated.

## PUB/MH II-35

**Subject:** Tab 4 Financial Results & Forecast
**Reference:** PUB/MH I-36 (a), IFRS Status Update Report Page 26

c) **For the two test years please provide a breakdown of the interest allocated to construction by major project. For illustrative purposes please show supporting calculations for the amount of interest allocated for the construction of the Wuskwatim G.S.**

## ANSWER:

**MANITOBA HYDRO ELECTRIC INC.**
**2010/11 & 2011/12 General Rate Application**

**PUB-MH II-35(c)**

| INTEREST ALLOCATED TO CONSTRUCTION | 2011 | (In Millions) 2012 |
|---|---|---|
| Wuskwatim | 64.39 | 52.11 |
| Keeyask | 27.76 | 38.34 |
| Conawapa | 15.16 | 20.32 |
| Riel 230/500kV Station | 4.53 | 9.12 |
| Bipole 3 Transmission and Converters | 2.65 | 4.68 |
| Pointe du Bois Modernization | 3.20 | 3.25 |
| Herblet Lake-The Pas 230 kV Transmission | 4.42 | 3.04 |
| Kelsey Re-runnering | 1.99 | 0.84 |
| Kettle Improvements & Upgrades | 0.65 | 0.51 |
| Firm Import/Export Upgrades | 0.06 | 0.28 |
| Base Capital | 5.99 | 4.65 |
| | **130.79** | **137.13** |

The Wuskwatim G.S does not lend itself well for illustrative purposes due to the complex nature of the partnership arrangements. As such, Manitoba Hydro has provided an illustration using the Conawapa GS.

## Illustration:

### Conawapa

**IFF09-1 - Monthly Projection**

(In Millions of Dollars)

| Date | CWIP Opening Balance | Construction Expenditures | Escalation | Capitalized Interest * | In-service Amount | CWIP Closing Balance |
|---|---|---|---|---|---|---|
| Apr-2010 | 197.29 | 3.99 | 0.02 | 1.09 | 0.00 | 202.39 |
| May-2010 | 202.39 | 3.87 | 0.02 | 1.15 | 0.00 | 207.43 |
| Jun-2010 | 207.43 | 4.45 | 0.03 | 1.14 | 0.00 | 213.05 |
| Jul-2010 | 213.05 | 4.26 | 0.03 | 1.21 | 0.00 | 218.55 |
| Aug-2010 | 218.55 | 4.06 | 0.03 | 1.25 | 0.00 | 223.90 |
| Sep-2010 | 223.90 | 4.26 | 0.04 | 1.23 | 0.00 | 229.43 |
| Oct-2010 | 229.43 | 4.06 | 0.04 | 1.31 | 0.00 | 234.85 |
| Nov-2010 | 234.85 | 3.29 | 0.04 | 1.30 | 0.00 | 239.47 |
| Dec-2010 | 239.47 | 3.15 | 0.04 | 1.36 | 0.00 | 244.03 |
| Jan-2011 | 244.03 | 3.01 | 0.04 | 1.39 | 0.00 | 248.47 |
| Feb-2011 | 248.47 | 3.00 | 0.05 | 1.28 | 0.00 | 252.80 |
| Mar-2011 | 252.80 | 3.44 | 0.06 | 1.44 | 0.00 | 257.74 |
| Total | | 44.85 | 0.43 | 15.16 | 0.00 | |

| Date | CWIP Opening Balance | Construction Expenditures | Escalation | Capitalized Interest * | In-service Amount | CWIP Closing Balance |
|---|---|---|---|---|---|---|
| Apr-2011 | 257.74 | 4.36 | 0.08 | 1.47 | 0.00 | 263.64 |
| May-2011 | 263.64 | 4.58 | 0.09 | 1.55 | 0.00 | 269.87 |
| Jun-2011 | 269.87 | 4.91 | 0.11 | 1.54 | 0.00 | 276.43 |
| Jul-2011 | 276.43 | 4.58 | 0.11 | 1.63 | 0.00 | 282.75 |
| Aug-2011 | 282.75 | 4.75 | 0.12 | 1.66 | 0.00 | 289.28 |
| Sep-2011 | 289.28 | 4.75 | 0.13 | 1.65 | 0.00 | 295.80 |
| Oct-2011 | 295.80 | 4.41 | 0.13 | 1.74 | 0.00 | 302.09 |
| Nov-2011 | 302.09 | 4.75 | 0.14 | 1.72 | 0.00 | 308.70 |
| Dec-2011 | 308.70 | 4.31 | 0.14 | 1.82 | 0.00 | 314.96 |
| Jan-2012 | 314.96 | 3.90 | 0.13 | 1.85 | 0.00 | 320.85 |
| Feb-2012 | 320.85 | 3.90 | 0.14 | 1.77 | 0.00 | 326.65 |
| Mar-2012 | 326.65 | 4.03 | 0.15 | 1.92 | 0.00 | 332.76 |
| Total | | 53.23 | 1.47 | 20.32 | 0.00 | |

* Interest Capitalization Rate for 2011 is 6.71% and 2012 is 6.95%

# 20

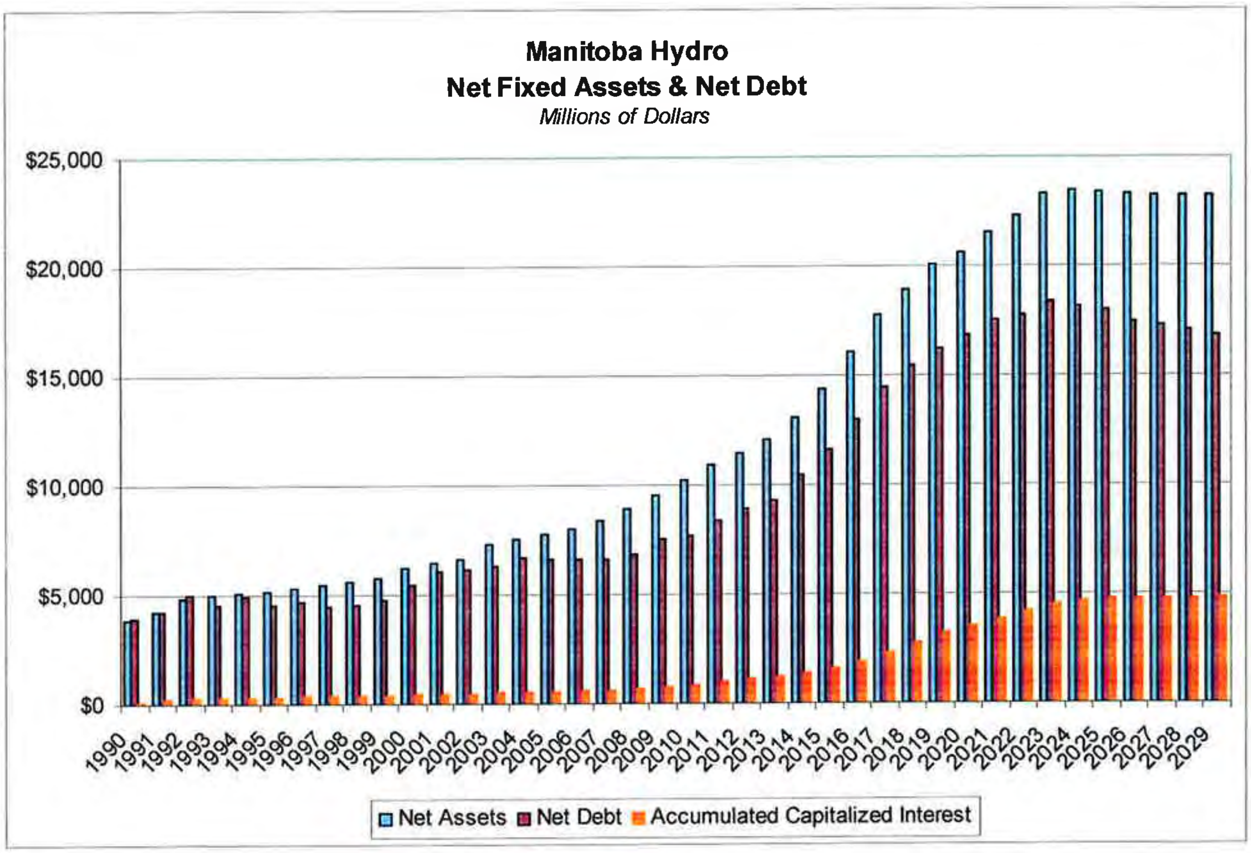
**PUB/MH I-69**

**Subject:** **Tab 6: Capital Expenditures**
**Reference:** **Appendix 6.2 Debt Management Strategy Page 4m Net Fixed Assets & Net Debt**

**a) Please recast the graph of Net Fixed Assets & Net Debt for the years 1990 through 2030 identifying the level of accumulated capitalized interest in each year. Please provide a table of corresponding data points.**

**ANSWER:**

Please note that as per the presentation in the Debt Management Strategy, the year end data points contained in this graph represent Consolidated Operations. The values for the years 1990 to 2009 are based on actuals, and 2010 to 2029 values are based on the forecast (IFF09).



The chart illustrates the growth in net fixed assets and net long term debt that has occurred over the past 20 years, as well as the projected growth in the decades of investment and returns. While net debt is expected to grow to approximately $16.9 billion as at March 31, 2029, the corresponding investment in generation, transmission, distribution and other assets is expected to grow at a much greater pace to a net book value of approximately $23.2 billion at March 31, 2029.

A table of corresponding data points is as follows:

| Year Ending | Net Assets | Capitalized Interest | Accumulated Capitalized Interest | Net Debt |
|---|---|---|---|---|
| 1990 | 3,882 | 97 | 97 | 3,889 |
| 1991 | 4,267 | 110 | 207 | 4,199 |
| 1992 | 4,857 | 72 | 279 | 4,972 |
| 1993 | 4,983 | 32 | 312 | 4,533 |
| 1994 | 5,067 | 16 | 328 | 4,948 |
| 1995 | 5,170 | 15 | 342 | 4,508 |
| 1996 | 5,310 | 19 | 361 | 4,685 |
| 1997 | 5,464 | 16 | 377 | 4,493 |
| 1998 | 5,608 | 20 | 396 | 4,559 |
| 1999 | 5,774 | 20 | 416 | 4,772 |
| 2000 | 6,235 | 15 | 431 | 5,488 |
| 2001 | 6,428 | 16 | 447 | 6,114 |
| 2002 | 6,626 | 26 | 473 | 6,146 |
| 2003 | 7,305 | 28 | 501 | 6,320 |
| 2004 | 7,536 | 32 | 532 | 6,675 |
| 2005 | 7,776 | 33 | 565 | 6,642 |
| 2006 | 8,010 | 34 | 600 | 6,614 |
| 2007 | 8,415 | 47 | 647 | 6,597 |
| 2008 | 8,912 | 60 | 707 | 6,870 |
| 2009 | 9,520 | 74 | 781 | 7,514 |
| 2010 | 10,246 | 92 | 873 | 7,728 |
| 2011 | 10,915 | 131 | 1,003 | 8,376 |
| 2012 | 11,472 | 137 | 1,141 | 8,919 |
| 2013 | 12,048 | 110 | 1,251 | 9,291 |
| 2014 | 13,081 | 144 | 1,395 | 10,426 |
| 2015 | 14,379 | 208 | 1,603 | 11,638 |
| 2016 | 16,058 | 306 | 1,909 | 12,999 |
| 2017 | 17,742 | 408 | 2,317 | 14,441 |
| 2018 | 18,958 | 449 | 2,766 | 15,470 |
| 2019 | 20,051 | 430 | 3,197 | 16,259 |
| 2020 | 20,648 | 365 | 3,562 | 16,854 |
| 2021 | 21,516 | 300 | 3,862 | 17,555 |
| 2022 | 22,324 | 353 | 4,215 | 17,787 |
| 2023 | 23,277 | 330 | 4,545 | 18,369 |
| 2024 | 23,454 | 160 | 4,704 | 18,169 |
| 2025 | 23,417 | 31 | 4,735 | 17,965 |
| 2026 | 23,335 | 30 | 4,765 | 17,494 |
| 2027 | 23,263 | 18 | 4,783 | 17,289 |
| 2028 | 23,232 | 23 | 4,805 | 17,079 |
| 2029 | 23,202 | 25 | 4,830 | 16,861 |

**PUB/MH I-69**

**Subject:** **Tab 6: Capital Expenditures**
**Reference:** **Appendix 6.2 Debt Management Strategy Page 4m Net Fixed Assets & Net Debt**

**b)** **Please provide a corresponding table of Net Assets, Net Debt, Retained Earnings and Debt to Equity ratio and Interest Coverage ratio of the corresponding years.**

**ANSWER:**

Please see the attached schedule.

Financial ratios are projected to weaken slightly in the first decade but rebound strongly in the second decade (the decade of returns).

| Year Ending | Net Assets | Net Debt | Retained Earnings | D/E Ratio | I/C Ratio |
|---|---|---|---|---|---|
| | *Millions of dollars* | *Millions of dollars* | *Millions of dollars* | | |
| | | | | | |
| 1990 | 3,882 | 3,889 | 117 | 95:05 | 1.07 |
| 1991 | 4,267 | 4,199 | 165 | 94:06 | 1.13 |
| 1992 | 4,857 | 4,972 | 183 | 94:06 | 1.04 |
| 1993 | 4,983 | 4,533 | 159 | 95:05 | 0.95 |
| 1994 | 5,067 | 4,948 | 228 | 93:07 | 1.16 |
| 1995 | 5,170 | 4,508 | 284 | 92:08 | 1.13 |
| 1996 | 5,310 | 4,685 | 354 | 91:09 | 1.16 |
| 1997 | 5,464 | 4,493 | 455 | 88:12 | 1.23 |
| 1998 | 5,608 | 4,559 | 566 | 86:14 | 1.25 |
| 1999 | 5,774 | 4,772 | 666 | 84:16 | 1.23 |
| 2000 | 6,235 | 5,488 | 818 | 83:17 | 1.35 |
| 2001 | 6,428 | 6,114 | 1,088 | 80:20 | 1.62 |
| 2002 | 6,626 | 6,146 | 1,302 | 77:23 | 1.42 |
| 2003 | 7,305 | 6,320 | 1,170 | 80:20 | 1.14 |
| 2004 | 7,536 | 6,675 | 734 | 87:13 | 0.17 |
| 2005 | 7,776 | 6,642 | 870 | 85:15 | 1.25 |
| 2006 | 8,010 | 6,614 | 1,285 | 81:19 | 1.77 |
| 2007 | 8,415 | 6,597 | 1,407 | 80:20 | 1.23 |
| 2008 | 8,912 | 6,870 | 1,822 | 76:24 | 1.69 |
| 2009 | 9,520 | 7,514 | 2,120 | 75:25 | 1.58 |
| 2010 | 10,246 | 7,728 | 2,227 | 74:26 | 1.24 |
| 2011 | 10,915 | 8,376 | 2,315 | 75:25 | 1.15 |
| 2012 | 11,472 | 8,919 | 2,396 | 76:24 | 1.15 |
| 2013 | 12,048 | 9,291 | 2,479 | 76:24 | 1.12 |
| 2014 | 13,081 | 10,426 | 2,616 | 78:22 | 1.19 |
| 2015 | 14,379 | 11,638 | 2,738 | 79:21 | 1.15 |
| 2016 | 16,058 | 12,999 | 2,997 | 80:20 | 1.30 |
| 2017 | 17,742 | 14,441 | 3,268 | 80:20 | 1.27 |
| 2018 | 18,958 | 15,470 | 3,515 | 80:20 | 1.23 |
| 2019 | 20,051 | 16,259 | 3,772 | 80:20 | 1.22 |
| 2020 | 20,648 | 16,854 | 4,059 | 79:21 | 1.22 |
| 2021 | 21,516 | 17,555 | 4,366 | 79:21 | 1.24 |
| 2022 | 22,324 | 17,787 | 4,816 | 78:22 | 1.36 |
| 2023 | 23,277 | 18,369 | 5,369 | 76:24 | 1.44 |
| 2024 | 23,454 | 18,169 | 6,113 | 73:27 | 1.58 |
| 2025 | 23,417 | 17,965 | 6,918 | 70:30 | 1.65 |
| 2026 | 23,335 | 17,494 | 7,840 | 66:34 | 1.77 |
| 2027 | 23,263 | 17,289 | 8,859 | 61:39 | 1.88 |
| 2028 | 23,232 | 17,079 | 9,986 | 56:44 | 2.02 |
| 2029 | 23,202 | 16,861 | 11,223 | 51:49 | 2.18 |

PUB/MH II-170 (B)

*In Millions*

| Year | Net Debt* | Net Interest Expense | Average Interest Rate | Total Capital Spending Attracting Interest** | Average Interest Rate on Capitalized Interest | Finance Expense allocated to Construction | % of Total Interest Expense |
|---|---|---|---|---|---|---|---|
| 2004/05 | 6,431 | 468 | 7.6% | 474 | 8.0% | 33 | 7% |
| 2005/06 | 6,277 | 468 | 8.0% | 600 | 6.6% | 34 | 7% |
| 2006/07 | 6,479 | 467 | 8.2% | 872 | 6.7% | 47 | 9% |
| 2007/08 | 6,485 | 401 | 7.2% | 1,232 | 6.7% | 60 | 13% |
| 2008/09 | 7,299 | 401 | 7.2% | 1,447 | 6.8% | 74 | 16% |
| 2009/10 | 7,462 | 417 | 6.8% | 1,947 | 6.5% | 92 | 18% |
| 2010/11 | 8,101 | 413 | 6.9% | 2,458 | 6.7% | 131 | 24% |
| 2011/12 | 8,627 | 468 | 7.2% | 1,341 | 7.0% | 137 | 23% |
| 2012/13 | 9,089 | 525 | 7.1% | 1,818 | 7.1% | 110 | 17% |
| 2013/14 | 10,072 | 527 | 7.0% | 2,838 | 7.0% | 144 | 21% |
| 2014/15 | 11,276 | 544 | 7.0% | 3,854 | 7.0% | 208 | 28% |
| 2015/16 | 12,728 | 529 | 6.9% | 5,532 | 7.0% | 306 | 37% |
| 2016/17 | 14,150 | 545 | 7.1% | 6,948 | 7.0% | 408 | 43% |
| 2017/18 | 15,132 | 587 | 7.1% | 6,159 | 7.0% | 449 | 43% |
| 2018/19 | 16,019 | 674 | 7.1% | 6,446 | 7.0% | 430 | 39% |
| 2019/20 | 16,462 | 878 | 7.6% | 4,168 | 7.0% | 365 | 29% |
| 2020/21 | 17,011 | 958 | 7.5% | 4,523 | 7.0% | 300 | 24% |
| 2021/22 | 17,367 | 851 | 7.0% | 5,453 | 7.0% | 353 | 29% |
| 2022/23 | 17,755 | 890 | 6.9% | 3,111 | 7.0% | 330 | 27% |
| 2023/24 | 17,189 | 1,071 | 7.0% | 877 | 7.0% | 160 | 13% |
| 2024/25 | 16,348 | 1,166 | 7.1% | 270 | 7.0% | 31 | 3% |
| 2025/26 | 15,347 | 1,126 | 7.3% | 119 | 7.0% | 30 | 3% |
| 2026/27 | 14,256 | 1,094 | 7.5% | 207 | 7.0% | 18 | 2% |
| 2027/28 | 13,093 | 1,037 | 7.7% | 205 | 7.0% | 23 | 2% |
| 2028/29 | 11,822 | 980 | 8.0% | 338 | 7.0% | 25 | 2% |

* *Represents total long-term debt plus current portion and short term debt less sinking fund assets and Centra Gas debt.*
***Represents Construction in Progress from the Balance Sheet as at March 31.*

# 21

## 6.0 IT IS THEREFORE ORDERED THAT:

1. Net Plant Additions to Rate Base for 2009/10 and 2010/11, as requested by Centra, BE AND ARE HEREBY APPROVED subject to the impact of Directives set out in this Order;

2. DSM expenditures included in Rate Base as a component of working capital allowance, BE AND ARE HEREBY APPROVED;

3. Centra's Application as filed and subsequently revised BE AND IS HEREBY APPROVED subject to the following:

   a. Finance Expense is adjusted by utilizing short term interest rate forecasts of 0.5% in 2009/10 and 1.0% in 2010/11, and long term interest rate forecasts of 4.0% in 2009/10 and 2010/11;

   b. $3.8 million is included in the revenue requirement for continuing the Furnace Replacement Program (FRP), and is to be funded by the Small General Service class;

   c. The $5 million accounting provision for IFRS and other risks to Centra in the second test year is denied;

   d. Amortization of DSM expenditures (with the exception of the expenditures related to the Furnace Replacement Program, which are to be expenses as incurred) is to be over a 10-year timeframe, consistent with the approach of Manitoba Hydro, on a prospective basis;

   e. Recovery of the majority of the revenue deficiency allocated to the SGS and LGS classes is to be by way of May 1, 2010 increases to the monthly BMC to $14 and $77, per month, respectively;

   f. The Primary Gas Overhead Rate, currently $1.63 per thousand cubic metres of natural gas, is to increase to $1.64/10$^3$m$^3$ effective May 1, 2010;

4. The Board directs that Centra continue to fund the FRP in the amount of $3.8 million per year through rates to the SGS class. $3.8 million is to accrue to the FRP account regardless of the weather impact on revenues. The FRP is to continue at this level of funding beyond the test years until such time as Centra receives alternative direction from the Board, and any unspent funds are to accrue interest at Centra's actual short term interest rate;

5. The Board directs Centra to file a semi-annual status update report on the FRP, to begin with a report by December 31, 2009;

6. Centra to develop and file with the Board a revised marketing and promotional plan for the LIEEP and FRP, designed to educate and encourage lower income consumers to participate;

7. Centra is to undertake and file with the Board by December 31, 2009 a demographic study that will assist it in reaching the target demographic for its lower income programs.

8. The Board confirms that Centra is to continue pricing its Fixed Rate Offerings according to the pricing formula approved in Order 156/08, excepting that the Program Cost Rate for all new offerings from this date shall be $0.0262/m^3$;

PUB/MH 1-46(A) 9. Centra to file for the Board's approval, by its next GRA, a revised interest rate forecasting methodology for rate setting purposes incorporating changes recommended by CAC/MSOS' witness Mr. McCormick, as follows:

   a. The use of all forecasts based on comparable average period data basis;

   b. The use and alignment of current date forecasts, excluding stale dated and superseded forecasts;

c. Utilization of forecasted long term interest rates which align with the period in which Centra intends on issuing new or refinancing existing long term debt;

d. A process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts;

e. The use of only statistically independent forecasts; and

f. A proposed process to update the forecast in advance of the hearing if warranted.

10. Centra to perform a true-up and adjustment on a quarterly basis to ensure there has been no over- or under-recovery of short-term finance costs charged to Centra from MH;

11. Centra to file on or before March 1, 2010 a terms of reference for a study to review the Integrated Cost Allocation Methodology. The study is to be completed in sufficient time to be incorporated within the corporation's next MH or Centra GRA;

12. Centra to calculate its DSM amortization for 2009/10 and thereafter based on a 10-year amortization period, and record its depreciation and amortization expense for rate setting purposes accordingly;

13. Centra to file a business plan with respect to the AMI project with the Board for its approval by January 15, 2010, and prior to proceeding beyond the pilot project expenditures. The business plan should include an assessment of the economic and non-economic benefits of AMI, including safety-related matters, for both the meter reader and for Centra's customers;

14. Changes to Centra's Terms and Conditions of Service regarding company labour rates for chargeable services BE AND ARE HEREBY APPROVED;

15. Changes to Centra's Terms and Conditions of Service relating to new requirements for Interruptible Service class customers BE AND ARE HEREBY APPROVED;

**PUB/MH I-46**

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates**

**a) Please describe what methodological changes have been employed by MH in forecasting interest rates given the recommendations provided by Mr. McCormick at the past Centra GRA and Board direction flowing from Order 128/09.**

**ANSWER:**

Ongoing enhancements are reflected in the forecast of interest rates that are embedded in the IFF for the years 2009/10 through 2012/13 as part of the updated information provided in Tab 5, page 2 and Appendix 5.2, page 5. These include:

- Only statistically independent forecasters were used in the update;
- Forecasts were based on comparable average period data basis;
- Current forecasts were used from each of the forecasters;
- Credit spread forecasts reflect 10 years of historical data where available. If not available, the longest period of historical data available on Bloomberg was utilized to calculate the mean.

The long-term Economic Outlook is produced annually in the spring of each year. A review of certain variables including short and long-term interest rates, exchange rate and CPI is conducted each summer for the first few years of the forecast and updated if required. Therefore, the interest rate forecasts in years 2013/14 and beyond reflected the Spring 2009 Economic Outlook as filed in Appendix 5.1.

**PUB/MH I-46**

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates**

**b) Please provide table(s) detailing the relied upon interest forecasts by forecaster for both short term and long term interest rates indicating, the date of the forecast, whether the forecast represented end of period data or average and describe what if any adjustments were made to end of period data forecasts to average the results.**

**ANSWER:**

Short and long term interest rates for 2009/10 - 2012/13 period were reviewed and revised in July 2009 based on currently available information. As noted in Tab 5.2, page 2, lines 1-16, the forecast of exchange rates and interest rates were again reviewed in October 2009 due to the continuing volatility of the Canadian dollar. This review resulted in a further revision to the long term Canadian debt rate for 2009/10 and 2010/11. The forecasts of interest rates for the 2013/14 - 2019/20 period are from the Spring 2009 Economic Outlook.

Table 1 on the following page depicts the sources used to derive the forecast of Canadian T-bill rates for the 2009/10 - 2012/13 period. Table 2 depicts the forecast sources used to derive the forecast of Canadian t-bill rates for the 2013/14 - 2019/20 period.

Table 3 depicts the sources used to derive the forecast of Canadian bond yield 10 yr+ rates for the 2009/10 - 2012/13 period. Table 4 depicts the forecast sources used to derive the forecast of Canadian bond yield 10 yr+ rates for the 2013/14 - 2019/20 period.

The information in Table 1 reflects actual 3 month T-bill rates from for Q1, Q2, and Q3 of 2009 (as indicated in shaded area). For the subsequent quarters, for forecasters that provided average period rates, the rates in Table 1 reflect the forecast provided from that forecaster. For forecasters that provided end of period rates, the rates in Table 1 reflect rates adjusted to a comparable average period basis. For example, Royal Bank's forecast provided end of period rates. Their forecast for 2009 Q4 end of period was 0.35%. In order to place the forecast on an equivalent average period basis for 2009 Q4, Royal Bank's 2009 Q4 end of period forecast of 0.35% was averaged with their 2009 Q3 end of period actual rate of 0.22% to approximate an average period 2009 Q4 forecast of 0.29%. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates in Table 1. i.e., Q1 end of period forecast for 2010 was averaged with Q4 end of period forecast for 2009 to obtain an average period Q1 2010 forecast, etc.

The information in Table 3 reflects actual rates for Q1, Q2, and Q3 of 2009 for the long bond rates applicable to each forecast source (as indicated in shaded area). The long bond rate used for each forecaster was as follows:

| **Forecaster** | **Long Bond Rate Used** |
|---|---|
| BMO Nesbitt Burns | Canada 10 Year |
| CIBC | Average of Canada 10 Yr and 30 Yr |
| National Bank | Average of Canada 10 Yr and 30 Yr |
| RBC | Average of Canada 10 Yr and 30 Yr |
| Scotiabank | Average of Canada 10 Yr and 30 Yr |
| TD Bank | Average of Canada 10 Yr and 30 Yr |
| Global Insight | Average of Canada 10 Yr and 30 Yr |
| Conference Board | Canada 10 Year+ |

With respect to Canadian long bond rate forecasts, BMO Nesbitt Burns only provides a Canadian 10 year forecast while the other five banks provide both 10 year and 30 year Canada long bond forecasts. Conference Board only provides a Canada 10 Year+ forecast. Global Insight provides a Canada 10 year, 30 year and 10 year+ forecast. For Global Insight, the average of the Canada 10 year and 30 year forecasts were used in the derivation of the forecasts in Table 3.

The actual rates in Table 3 for Q1, Q2, and Q3 2009 reflect the actual Canada 10 year bond rate for BMO Nesbitt Burns, the average of the actual Canada 10 year bond and 30 year bond rates for CIBC, National Bank, RBC, Scotiabank, TD Bank and Global Insight and the actual Canada 10 Year+ rate for Conference Board, consistent with the forecast rates used for each of those sources.

For the subsequent quarters, for forecasters that provided average period rates, the rates in Table 3 reflect the forecast provided from that forecaster. For forecasters that provided end of period rates, the rates in Table 3 reflect rates adjusted to a comparable average period basis. For example, Royal Bank's forecast provided end of period rates. Their forecast for 2009 Q4 end of period was 3.15% for Canada 10 year and 4.00% for Canada 30 year (average of 3.58%). In order to place the forecast on an equivalent basis for a Q4 average period forecast, Royal Bank's Q4 end of period forecast of 3.58% was averaged with their Q3 end of period actual rate of 3.58% (average of 3.31% for Canada 10 year and 3.84% for Canada 30 year) to approximate an average period Q4 forecast of 3.58%. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates in Table 3. i.e., Q1 end of period forecast for 2010 was averaged with Q4 end of period forecast for 2009 to obtain an average period Q1 2010 forecast, etc.

It should be noted that adjusting end of period forecasts to average forecasts may or may not result in a better consolidated forecast. The result is still a forecast which will be updated in subsequent periods and will ultimately be updated to actual borrowing rates. The adjustments which put all of the independent forecasts on an equivalent basis have the potential to qualify, to some extent, the independence of externally derived forecasts. Further, the use of end of period versus average is normally immaterial in the overall scheme of the financial forecast which has many moving parts. Nevertheless, such adjustments may have some value during extreme volatility in rates.

**Table 1 - Canada 90 Day T-bill Rate - %**

| | | | 2009 | | | | 2010 | | | | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fcst Date | End Period or Average | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| BMO Nesbitt Burns | 09-Oct-09 | Average | 0.71 | 0.23 | 0.23 | 0.22 | 0.22 | 0.30 | 0.78 | 1.25 | | | | | | | | | | | | |
| CIBC | 30-Sep-09 | End Period | 0.71 | 0.23 | 0.23 | 0.24 | 0.24 | 0.28 | 0.30 | 0.30 | | | | | | | | | | | | |
| National Bank | Oct-09 | End Period | 0.71 | 0.23 | 0.23 | 0.29 | 0.64 | 1.21 | 1.69 | 2.05 | | | | | | | | | | | | |
| Royal Bank | 02-Oct-09 | End Period | 0.71 | 0.23 | 0.23 | 0.29 | 0.43 | 0.63 | 1.00 | 1.55 | | | | | | | | | | | | |
| Scotiabank | 07-Oct-09 | End Period | 0.71 | 0.23 | 0.23 | 0.27 | 0.33 | 0.43 | 0.90 | 1.78 | | | | | | | | | | | | |
| TD Bank | 15-Oct-09 | End Period | 0.71 | 0.23 | 0.23 | 0.27 | 0.30 | 0.38 | 0.53 | 0.75 | | | | | | | | | | | | |
| IHS Global Insight | 09-Oct-09 | Average | 0.71 | 0.23 | 0.23 | 0.25 | 0.28 | 0.53 | 0.79 | 1.30 | 1.98 | 2.24 | 2.50 | 2.75 | 3.00 | 3.25 | 3.50 | 3.75 | 4.00 | 4.25 | 4.50 | 4.50 |
| Conference Board | 16-Sep-09 | Average | 0.71 | 0.23 | 0.23 | 0.20 | 0.18 | 0.25 | 0.69 | 1.47 | 2.46 | 3.44 | 4.14 | 4.54 | 4.58 | 4.58 | 4.59 | 4.59 | 4.60 | 4.60 | 4.60 | 4.60 |
| Average | | | 0.71 | 0.23 | 0.23 | 0.25 | 0.33 | 0.50 | 0.83 | 1.31 | 2.22 | 2.84 | 3.32 | 3.65 | 3.79 | 3.92 | 4.05 | 4.17 | 4.30 | 4.42 | 4.55 | 4.55 |
| | | | **2009/10** | **2010/11** | **2011/12** | **2012/13** | | | | | | | | | | | | | | | | |
| **EO2009 - Fiscal** | | | 0.25 | 1.20 | 3.40 | 4.10 | | | | | | | | | | | | | | | | |

**Table 2 - Canada 90 Day T-Bill Rate - %**

| | | End Period or Average | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| IHS Global Insight | Feb-09 | Average | 4.31 | 4.75 | 4.75 | 4.75 | 4.50 | 4.50 | 4.50 | 4.50 |
| Conference Board | Dec-08 | Average | 4.60 | 4.60 | 4.60 | 4.61 | 4.61 | 4.61 | 4.61 | 4.61 |
| Informetrica | Feb-09 | Average | 3.90 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 |
| Spatial Economics | Nov-08 | Average | 5.10 | 4.30 | 3.70 | 3.50 | 3.60 | 4.20 | 4.60 | 4.70 |
| Province of BC | Feb-09 | Average * | 4.80 | | | | | | | |
| Federal Finance | Nov-08 | Average * | 4.20 | | | | | | | |
| Average | | | 4.48 | 4.36 | 4.21 | 4.17 | 4.13 | 4.28 | 4.38 | 4.40 |
| EO2009 - Calendar | | | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 |
| | | | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **2018/19** | **2019/20** | |
| EO2009 - Fiscal | | | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | 4.25 | |

* The source forecast tables do not indicate end period or average period. Manitoba Hydro has treated them as average period rates

**Table 3 - Canada Bond Yield 10 Year+ Rate - %**

| | | | 2009 | | | | 2010 | | | | 2011 | | | | 2012 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End Period or Average | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| BMO Nesbitt Burns | 09-Oct-09 | Average | 2.96 | 3.37 | 3.41 | 3.30 | 3.43 | 3.54 | 3.65 | 3.76 | | | | | | | | | | | | |
| CIBC | 30-Sep-09 | End Period | 3.34 | 3.67 | 3.67 | 3.60 | 3.70 | 3.89 | 4.03 | 4.11 | | | | | | | | | | | | |
| National Bank | Oct-09 | End Period | 3.34 | 3.67 | 3.67 | 3.82 | 4.08 | 4.24 | 4.32 | 4.41 | | | | | | | | | | | | |
| Royal Bank | 02-Oct-09 | End Period | 3.34 | 3.67 | 3.67 | 3.58 | 3.63 | 3.78 | 3.98 | 4.19 | | | | | | | | | | | | |
| Scotiabank | 07-Oct-09 | End Period | 3.34 | 3.67 | 3.67 | 3.66 | 3.85 | 4.19 | 4.54 | 4.73 | | | | | | | | | | | | |
| TD Bank | 15-Oct-09 | End Period | 3.34 | 3.67 | 3.67 | 3.73 | 3.85 | 3.75 | 3.74 | 3.94 | | | | | | | | | | | | |
| IHS Global Insight | 09-Oct-09 | Average | 3.34 | 3.67 | 3.67 | 4.03 | 4.07 | 4.08 | 4.09 | 4.12 | 4.16 | 4.21 | 4.23 | 4.41 | 4.66 | 4.87 | 4.93 | 4.93 | 4.93 | 4.95 | 5.13 | 5.60 |
| Conference Board | 16-Sep-09 | Average | 3.69 | 3.93 | 3.98 | 3.96 | 3.71 | 3.53 | 3.54 | 3.72 | 4.03 | 4.41 | 4.72 | 4.96 | 5.07 | 5.18 | 5.28 | 5.36 | 5.43 | 5.49 | 5.55 | 5.60 |
| **Average** | | | **3.34** | **3.67** | **3.68** | **3.71** | **3.79** | **3.87** | **3.98** | **4.12** | **4.10** | **4.31** | **4.47** | **4.69** | **4.87** | **5.03** | **5.10** | **5.14** | **5.18** | **5.22** | **5.34** | **5.60** |
| | | | **2009/10** | **2010/11** | **2011/12** | **2012/13** | | | | | | | | | | | | | | | | |
| **EO2009 - Fiscal** | | | 3.70 | 4.00 | 4.60 | 5.10 | | | | | | | | | | | | | | | | |

**Table 4 - Canada Bond Yield 10 Year+ Rate - %**

| | | End Period or Average | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| IHS Global Insight | Feb-09 | Average | 5.27 | 5.94 | 5.93 | 5.93 | 5.93 | 5.92 | 5.92 | 5.92 |
| Conference Board | Dec-08 | Average | 5.64 | 5.75 | 5.82 | 5.86 | 5.88 | 5.90 | 5.91 | 5.91 |
| Informetrica | Feb-09 | Average | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 | 4.80 | 4.80 |
| Spatial Economics | Nov-08 | Average | 7.20 | 6.40 | 5.70 | 5.40 | 4.90 | 5.50 | 5.90 | 6.00 |
| Province of BC | Feb-09 | Average * | 5.80 | | | | | | | |
| Federal Finance | Nov-08 | Average * | 5.00 | | | | | | | |
| Consensus Economics | Oct-08 | End Period | 5.20 | 5.10 | 5.10 | 5.10 | 5.10 | 5.10 | | |
| Average | | | 5.57 | 5.62 | 5.49 | 5.44 | 5.34 | 5.46 | 5.63 | 5.66 |
| EO2009 - Calendar | | | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 |
| | | | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **2018/19** | **2019/20** | |
| EO2009 - Fiscal | | | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | 5.50 | |

* The source forecast tables do not indicate end period or average period. Manitoba Hydro has treated them

PUB/MH I-46

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates**

**d) Please file the detailed calculations in support of the short and long term interest rates utilized for MH's fiscal years 2009/10, 2010/11 & 2011/12 with narrative of the steps taken to derive the forecast.**

**ANSWER:**

Refer to the response to PUB/MH I-46(b), Table 1 and Table 3 for the detailed information on the 90 day T-Bill and Canada Bond Yield 10 year+ rates, respectively, for the 2009/10, 2010/11 and 2011/12 periods. The calculations of the rates were as follows:

- The average of the forecasts was calculated for Canada 90 day T-Bills and Canada Bond Yield 10 year+ rates for each quarter. For example, the average for Q4 2010 for the forecasts was 1.31% for Canada 90 day T-Bills and 4.12% for Canada Bond Yield 10 year+ rates, as depicted in Table 1 and Table 3, respectively.

- The fiscal year average was calculated using the quarters applicable to that fiscal year. The 2009/10 forecast included the average of Q2, Q3, Q4 of 2009 and Q1 of 2010. The 2010/11 forecast included the average of Q2, Q3, Q4 of 2010 and Q1 of 2011. The 2011/12 forecast included the average of Q2, Q3, Q4 of 2011 and Q1 of 2012. For example, the Canada 90 day T-Bill rate for 2010/11 of 1.20% in Table 1 was calculated as follows:

| | |
|---|---|
| 2010 Q2: | 0.50% |
| 2010 Q3: | 0.83% |
| 2010 Q4: | 1.31% |
| 2011 Q1: | 2.22% |
| Average: | 1.21% rounds to 1.20% |

- The Manitoba Hydro Canadian short term rate (exclusive of the guarantee fee of 1.00%) was calculated by adding the appropriate spread (between the 3 month T-Bill interest rate and 3 month Bloomberg BA interest rate) to the 90 day T-Bill rate as follows:

| | Canada 90 day T-Bill | Spread | MH Cdn Short Term Rate |
|---|---|---|---|
| 2009/10 | 0.25% | 0.20% | 0.45% |
| 2010/11 | 1.20% | 0.20% | 1.40% |
| 2011/12 | 3.40% | 0.20% | 3.60% |

As part of IFF preparations, in the summer of 2009, Manitoba Hydro reviewed the actual year to date spreads during 2009/10. The first fiscal quarter had a spread of 20 basis points and a decision was made to utilize a 20 basis point spread for the balance of the forecasting period.

In October 2009, the calculation of the historic average spread was revisited. For comparative purposes, weekly Bloomberg data sources were utilized to obtain the 3 month T-Bill interest rate and 3 month Bloomberg BA interest rate (C1033M and CDOR03 respectively). Three month BAs are utilized for forecasting purposes as predominantly most of the floating rate Canadian long-term debt utilizes this basis for resets. In light of the recent credit crisis and in order to obtain greater longitudinal data, the historic period for analysis was extended from 5 to 10 years (note that aforementioned Bloomberg indices commenced October 2000 and as such become the starting point for the analysis). The historic spread from October 2000 to October 2009 was just over 23 basis points. Given the immateriality of the difference between this 10 year historic average and the actual fiscal year to date results, the 20 basis point short term spread was retained for forecasting purposes.

- The Manitoba Hydro Canadian long term rate (exclusive of the guarantee fee) was calculated by adding the appropriate credit spread to Canada Bond Yield 10 Year+ rate as follows:

| | Canada Bond Yield 10 Yr+ | Spread | MH Cdn Long Term Rate |
|---|---|---|---|
| 2009/10 | 3.70% | 0.90% | 4.60% |
| 2010/11 | 4.00% | 0.65% | 4.65% |
| 2011/12 | 4.60% | 0.60% | 5.20% |

Please see Manitoba Hydro's response to CAC/MSOS/MH I-31(b) for detailed calculations of the forecast long term spreads.

**PUB/MH I-46**

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates**

e) **Please provide an analysis which shows how the long term borrowing rates of 4.65% for 2010/11 and 5.20% for 2011/12 was derived. In that analysis please provide the projected Manitoba to Canada spread.**

**ANSWER:**

Please refer to Manitoba Hydro's response to PUB/MH I-46(d) for the explanation of the derivation of the long term borrowing rates for 2010/11 and 2011/12 which includes the Manitoba to Canada borrowing spread.

The Canadian GOC 10 Yr+ rates for 2010/11 and 2011/12 were derived as explained in the response to PUB/MH I-46(b).

**PUB/MH I-46**

**Subject:** **Tab 5: Integrated Financial Forecast**
**Reference:** **Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates**

**f)** **Please describe with detailed calculations how the forecasted Manitoba to Canada spreads in part e) were determined.**

**ANSWER:**

A historical spread is considered as part of the interest rate forecast. The mean of the historical spread is determined utilizing ten years of historical index information from Bloomberg. The all-in historical spread (including commissions) incorporated into the forecasted long term Canadian debt rate of 0.60% for 2011/12 was calculated by taking an average of the 10 year and 30 year credit spreads from Bloomberg and commissions supplied by various financial institutions in the Province of Manitoba's debt syndicate. The all-in historical spread was calculated as follows:

| | | |
|---|---|---|
| 30 Year Canadian Index | | |
| C30230Y | 5.46 | Prov of MB Curve |
| C10130Y | 4.85 | Canada Govt Curve |
| 30 Year Spread | 0.61 | |
| 10 Year Canadian Index | | |
| C30210Y | 5.11 | Prov of MB Curve |
| C10110Y | 4.66 | Canada Govt Curve |
| 10 Year Spread | 0.45 | |
| Average of 10 & 30 Year Spreads | 0.53 | |
| Commissions | | |
| Average 10 & 30 Year | 0.06 | |
| Total Spread & Commissions | 0.59 | |

On the basis that the financial markets will return to a more normal environment in 2011/12, the all-in spread of 0.65% for 2010/11 was calculated by taking an average of the quarterly spread forecasts. The quarterly spread forecasts were derived from a straight-line interpolation from the all-in spread at the end of 2009/10 Quarter 2: 0.75% and the 2011/12 all-in spread of 0.60% (rounded using the aforementioned historical average).

# 22

MANITOBA HYDRO
FINANCE EXPENSE

PUB 1-35(b)

Schedule 4.6.0 Revised for PU B 1-35(b)
(000s)

| Schedule 4.6.0 As Filed: | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|
| Interest on Short & Long-Term Debt | | | | | |
| Gross Interest | $ 500,512 | $ 468,685 | $ 475,783 | $ 492,011 | $ 553,011 |
| Provincial Guarantee Fee | 69,865 | 70,360 | 72,274 | 78,099 | 82,920 |
| Amortization of (Premiums), Discounts, and Transaction Costs | (11,054) | (11,605) | (10,498) | 2,321 | 2,276 |
| Intercompany Interest Receivable | (19,774) | (18,182) | (16,380) | (19,416) | (25,015) |
| Total Interest on Short & Long-Term Debt | 539,549 | 509,259 | 521,179 | 553,015 | 613,192 |
| Interest Earned on Sinking Fund | (30,180) | (24,920) | (24,908) | (17,585) | (10,720) |
| Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges | (52,407) | (11,359) | 8,011 | 4,398 | - |
| Interest Allocated to Construction | (60,015) | (74,493) | (91,267) | (130,789) | (137,126) |
| Corporate Allocation | (17,483) | (17,543) | (17,880) | (18,704) | (18,704) |
| Other Amortization | 21,331 | 20,116 | 21,776 | 22,204 | 21,008 |
| **Total Finance Expense** | $ 400,796 | $ 401,060 | $ 416,913 | $ 412,539 | $ 467,650 |

| Schedule 4.6.0 Revised for PUB/MH I - 35 (b): | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|
| Interest on Short & Long-Term Debt | | | | | |
| Gross Interest | $ 500,512 | $ 468,685 | $ 475,875 | $ 483,869 | $ 543,345 |
| Provincial Guarantee Fee | 69,865 | 70,360 | 72,274 | 78,100 | 82,895 |
| Amortization of (Premiums), Discounts, and Transaction Costs | (11,054) | (11,605) | (10,498) | 2,321 | 2,276 |
| Intercompany Interest Receivable | (19,774) | (18,182) | (16,421) | (18,197) | (24,285) |
| Total Interest on Short & Long-Term Debt | 539,549 | 509,259 | 521,230 | 546,093 | 604,231 |
| Interest Earned on Sinking Fund | (30,180) | (24,920) | (24,908) | (17,569) | (10,720) |
| Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges | (52,407) | (11,359) | 8,011 | 4,398 | - |
| Interest Allocated to Construction | (60,015) | (74,493) | (91,267) | (120,284) | (132,636) |
| Corporate Allocation | (17,483) | (17,543) | (17,880) | (18,704) | (18,704) |
| Other Amortization | 21,331 | 20,116 | 21,776 | 22,204 | 21,008 |
| **Total Finance Expense utilizing short and long term interest rates approved by the Board at the Centra GRA** | $ 400,796 | $ 401,060 | $ 416,964 | $ 416,138 | $ 463,179 |

| Difference from Schedule 4.6.0 as Filed | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|
| Interest on Short & Long-Term Debt | | | | | |
| Gross Interest | $ - | $ - | $ 92 | $ (8,142) | $ (9,666) |
| Provincial Guarantee Fee | - | - | - | 1 | (25) |
| Amortization of (Premiums), Discounts, and Transaction Costs | - | - | - | - | - |
| Intercompany Interest Receivable | - | - | (41) | 1,219 | 730 |
| Total Interest on Short & Long-Term Debt | - | - | 51 | (6,922) | (8,961) |
| Interest Earned on Sinking Fund | - | - | - | 16 | - |
| Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges | - | - | - | - | - |
| Interest Allocated to Construction | - | - | - | 10,505 | 4,490 |
| Corporate Allocation | - | - | - | - | - |
| Other Amortization | - | - | - | - | - |
| **Total Finance Expense Increase (Decrease) from IFF-09** | $ - | $ - | $ 51 | $ 3,599 | $ (4,471) |

PUB/MH I-35

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

**d) Please provide a continuity schedule of the short and long-term debt for the fiscal years 2000 to 2030 detailing the retirement of existing debt and the issue of new debt. Please indicate the proportion of short-term debt to total debt for each of the years.**

**ANSWER:**

Please see the attached schedule.

Short term debt is defined as debt issued with maturities of less than one year. Manitoba Hydro's short term borrowing program is a credit facility to safeguard Manitoba Hydro from liquidity risk and to provide sufficient liquidity for the Corporation's temporary cash requirements. Short term borrowings are not intended as a financing vehicle to reduce Manitoba Hydro's overall debt servicing costs.

Manitoba Hydro uses its short term debt line to fund seasonal working capital requirements and to bridge the timing between long term debt issues. It is inappropriate to utilize the Corporation's overdraft credit facilities and Commercial Paper Program to permanently fund capital construction that should more appropriately be financed through long term debt.

PUB 1-35(d)

**MANITOBA HYDRO**
**CONTINUNITY SCHEDULE**
**SHORT AND LONG TERM DEBT**

**Actuals to March 31, 2009**
**(In $Millions Canadian Dollars)**

| | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Actual 2008 | Actual 2009 | Forecast 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 | Forecast 2014 | Forecast 2015 | Forecast 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Long Term Debt** | | | | | | | | | | | | | |
| Opening Balance | 7,268 | 7,390 | 7,204 | 7,169 | 7,227 | 7,570 | 8,179 | 8,118 | 8,637 | 9,251 | 9,631 | 10,462 | 11,780 |
| LTD Issued | 1,013 | 300 | 180 | 173 | 981 | 423 | 900 | 800 | 600 | 600 | 1,600 | 1,400 | 1,800 |
| LTD Retired | (473) | (241) | (111) | (80) | (311) | (365) | (448) | (304) | (27) | (183) | (849) | (100) | (262) |
| Foreign Exchange and Adjustments* | (418) | (245) | (104) | (35) | (328) | 552 | (514) | 23 | 41 | (36) | 80 | 18 | 19 |
| Closing Balance | 7,390 | 7,204 | 7,169 | 7,227 | 7,570 | 8,179 | 8,118 | 8,637 | 9,251 | 9,631 | 10,462 | 11,780 | 13,337 |

Foreign Exchange and Adjustments* includes changes in foreign exchange rates on US dollar denominated debt and effective 2007/08 and 2008/09 with presentation changes from financial instruments reporting standards includes changes to portfolio carrying value from premiums/discounts and transaction costs.

| **Short Term Debt** | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Actual 2008 | Actual 2009 | Forecast 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 | Forecast 2014 | Forecast 2015 | Forecast 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Opening Balance | 128 | 93 | 59 | - | 148 | - | 100 | 48 | 40 | 23 | 109 | - | - |
| Increase(Decrease) | (35) | (34) | (59) | 148 | (148) | 100 | (52) | (8) | (17) | 86 | (109) | - | 41 |
| Closing Balance | 93 | 59 | - | 148 | - | 100 | 48 | 40 | 23 | 109 | - | - | 41 |

| | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Actual 2008 | Actual 2009 | Forecast 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 | Forecast 2014 | Forecast 2015 | Forecast 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Long Term Debt | 7,390 | 7,204 | 7,169 | 7,227 | 7,570 | 8,179 | 8,118 | 8,637 | 9,251 | 9,631 | 10,462 | 11,780 | 13,337 |
| Short Term Debt | 93 | 59 | - | 148 | - | 100 | 48 | 40 | 23 | 109 | - | - | 41 |
| Total Debt | 7,483 | 7,263 | 7,169 | 7,375 | 7,570 | 8,279 | 8,166 | 8,677 | 9,274 | 9,740 | 10,462 | 11,780 | 13,378 |
| | | | | | | | | | | | | | |
| Proportion Short Term Debt | 1% | 1% | 0% | 2% | 0% | 1% | 1% | 0% | 0% | 1% | 0% | 0% | 0% |

PUB 1-35(d)

**MANITOBA HYDRO**
**CONTINUNITY SCHEDULE**
**SHORT AND LONG TERM DEBT**

**Actuals to March 31, 2009**
**(In $Millions Canadian Dollars)**

| **Long Term Debt** | Forecast 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 | Forecast 2021 | Forecast 2022 | Forecast 2023 | Forecast 2024 | Forecast 2025 | Forecast 2026 | Forecast 2027 | Forecast 2028 | Forecast 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Opening Balance | 13,337 | 14,955 | 16,228 | 16,763 | 17,445 | 18,164 | 18,022 | 18,653 | 18,656 | 18,658 | 18,360 | 18,362 | 18,364 |
| LTD Issued | 1,800 | 1,800 | 1,400 | 1,000 | 1,000 | 600 | 800 | - | - | - | - | - | - |
| LTD Retired | (201) | (530) | (869) | (321) | (285) | (745) | (171) | - | - | (300) | - | - | (60) |
| Foreign Exchange and Adjustments* | 19 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Closing Balance | 14,955 | 16,228 | 16,763 | 17,445 | 18,164 | 18,022 | 18,653 | 18,656 | 18,658 | 18,360 | 18,362 | 18,364 | 18,306 |

Foreign Exchange and Adjustments* includes changes in foreign exchange rates on US dollar denominated debt and effective 2007/08 and 2008/09 with presentation changes from financial instruments reporting standards includes changes to portfolio carrying value from premiums/discounts and transaction costs

| **Short Term Debt** | Forecast 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 | Forecast 2021 | Forecast 2022 | Forecast 2023 | Forecast 2024 | Forecast 2025 | Forecast 2026 | Forecast 2027 | Forecast 2028 | Forecast 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Opening Balance | 41 | 21 | - | 72 | - | - | - | - | - | - | - | - | - |
| Increase(Decrease) | (20) | (21) | 72 | (72) | - | - | - | - | - | - | - | - | - |
| Closing Balance | 21 | - | 72 | - | - | - | - | - | - | - | - | - | - |

| | Forecast 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 | Forecast 2021 | Forecast 2022 | Forecast 2023 | Forecast 2024 | Forecast 2025 | Forecast 2026 | Forecast 2027 | Forecast 2028 | Forecast 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Long Term Debt | 14,955 | 16,228 | 16,763 | 17,445 | 18,164 | 18,022 | 18,653 | 18,656 | 18,658 | 18,360 | 18,362 | 18,364 | 18,306 |
| Short Term Debt | 21 | - | 72 | - | - | - | - | - | - | - | - | - | - |
| Total Debt | 14,976 | 16,228 | 16,835 | 17,445 | 18,164 | 18,022 | 18,653 | 18,656 | 18,658 | 18,360 | 18,362 | 18,364 | 18,306 |
| Proportion Short Term Debt | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

**PUB/MH I-35**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

**e) Please provide a schedule of new debt issues of long-term borrowings for the years 2009/10, 2010/11 and 2011/12 years and the forecast and Interest per year at forecast rate interest rates used for each loan.**

**ANSWER:**

Please see the attached schedule.

PUB 1-35 (e)

**New Long Term Debt Issues**
**Forecast as at September 30, 2009 in Schedule 4.6.0 Interest Costs**
**(all amounts in $millions)**
**(rates exclude PGF)**

| Fiscal Year | Series | Amount | Currency | Issue Date | Maturity Date | Coupon Rate | Interest Cost 2009/10 | Interest Cost 2010/11 | Interest Cost 2011/12 |
|---|---|---|---|---|---|---|---|---|---|
| **2009/10** | C107 | 100.0 | CAD | 2-Jun-2009 | 4-Sep-2012 | Floating 3 BA + 0.40% | 0.7 | 1.6 | 3.6 |
| | FK-2 | 300.0 | CAD | 5-Jun-2009 | 5-Mar-2040 | 4.65% | 11.6 | 14.0 | 14.0 |
| | FM-4 | 100.0 | CAD | 1-Sep-2009 | 1-Sep-2014 | Floating 3 BA + 0.484% | 0.6 | 1.8 | 3.7 |
| | Forecast | 200.0 | CAD | Feb-2010 | Feb-2040 | 4.60% | 0.8 | 9.2 | 9.2 |
| | Forecast | 200.0 | CAD | Mar-2010 | Mar-2040 | 4.60% | 0.0 | 9.2 | 9.2 |
| | Total New Debt | 900.0 | | | | | 13.7 | 35.8 | 39.7 |
| **2010/11** | Forecast | 200.0 | CAD | Jun-2010 | Jun-2040 | 4.65% | | 7.0 | 9.3 |
| | Forecast | 200.0 | CAD | Aug-2010 | Aug-2040 | 4.65% | | 5.4 | 9.3 |
| | Forecast | 200.0 | CAD | Nov-2010 | Nov-2040 | 4.65% | | 3.1 | 9.3 |
| | Forecast | 200.0 | CAD | Mar-2011 | Mar-2041 | 4.65% | | 0.0 | 9.3 |
| | Total New Debt | 800.0 | | | | | | 15.5 | 37.2 |
| **2011/12** | Forecast | 200.0 | CAD | Sep-2011 | Sep-2041 | 5.20% | | | 5.2 |
| | Forecast | 200.0 | CAD | Dec-2012 | Dec-2042 | 5.20% | | | 2.6 |
| | Forecast | 200.0 | CAD | Mar-2012 | Mar-2042 | 5.20% | | | 0.0 |
| | Total New Debt | 600.0 | | | | | | | 7.8 |

**PUB/MH I-35**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

**h) For each of the years 2004 through 2013, assuming the refinancing plan in the application, please provide weighted average term of outstanding debt, the principal amount and proportion of debt maturing within:**

**i. 10 years;**
**ii. Twenty years; and**
**iii. Greater than twenty years**

**ANSWER:**

Please see the attached schedule that reflects long term debt balances and the refinancing plan as at September 30, 2009.

**MANITOBA HYDRO**
**PUB 1-35(h)**
**AS AT SEPTEMBER 30, 2009**

| Fiscal Year Ended | Debt Maturing <= 10 Years CAD$Millions | Debt Maturing <= 10 Years % of Total | Debt Maturing > 10 years and <= 20 Years CAD$Millions | Debt Maturing > 10 years and <= 20 Years % of Total | Debt Maturing > 20 Years CAD$Millions | Debt Maturing > 20 Years % of Total | Total Long Term Debt CAD$Millions | Weighted Average Term To Maturity In Years |
|---|---|---|---|---|---|---|---|---|
| March 31, 2004 | $2,586 | 35.1% | $3,521 | 47.7% | $1,268 | 17.2% | $7,375 | 13.8 |
| March 31, 2005 | 2,377 | 33.1% | 3,346 | 46.5% | 1,468 | 20.4% | 7,191 | 13.8 |
| March 31, 2006 | 2,397 | 33.5% | 3,317 | 46.3% | 1,443 | 20.2% | 7,158 | 13.7 |
| March 31, 2007 | 2,623 | 36.3% | 3,094 | 42.9% | 1,501 | 20.8% | 7,218 | 12.9 |
| March 31, 2008 | 2,996 | 39.5% | 2,513 | 33.1% | 2,081 | 27.4% | 7,590 | 13.5 |
| March 31, 2009 | 3,763 | 45.8% | 2,026 | 24.7% | 2,421 | 29.5% | 8,209 | 13.6 |
| March 31, 2010 | 3,583 | 43.8% | 1,726 | 21.1% | 2,871 | 35.1% | 8,180 | 14.9 |
| March 31, 2011 | 3,558 | 40.9% | 2,069 | 23.8% | 3,071 | 35.3% | 8,698 | 15.8 |
| March 31, 2012 | 4,265 | 45.8% | 1,383 | 14.9% | 3,662 | 39.3% | 9,310 | 15.8 |
| March 31, 2013 | 4,207 | 43.4% | 1,249 | 12.9% | 4,232 | 43.7% | 9,688 | 16.0 |
| March 31, 2014 | 3,435 | 32.7% | 1,249 | 11.9% | 5,832 | 55.5% | 10,516 | 18.4 |

# 23

**PUB/MH I-37 (REVISED)**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4- Schedule 4.7.0 Depreciation & Amortization**

**a) Please re-file the schedule including the years 1999/00 through 2006/07**

**ANSWER:**

Please see the following schedule, which includes information from 2003/04 through 2011/12.

| | 2003/04 Actual | 2004/05 Actual | 2005/06 Actual | 2006/07 Actual | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|---|---|---|---|
| **Generation** | | | | | | | | | |
| Hydraulic Generating Stations | 58,336 | 59,815 | 60,615 | 61,596 | 68,451 | 70,911 | 75,678 | 79,051 | 87,683 |
| Thermal Generating Stations | 17,098 | 16,857 | 17,019 | 17,191 | 17,170 | 17,276 | 17,661 | 18,234 | 18,660 |
| Amortization of Planning Studies | 4,168 | 4,621 | 5,485 | 2,437 | 2,366 | 2,539 | 0 | 0 | 0 |
| Demand Side Management | 5,024 | 5,957 | 7,247 | 9,973 | 11,357 | 20,102 | 21,943 | 24,829 | 28,703 |
| Diesel Generating Stations | 2,742 | 3,029 | 3,126 | 3,197 | 4,067 | 3,933 | 3,572 | 3,695 | 3,893 |
| Amortization of Contributions | (37) | (22) | (1,335) | (2,660) | (2,774) | (2,796) | (2,824) | (2,923) | (3,206) |
| | $ 87,331 | $ 90,257 | $ 92,157 | $ 91,734 | $ 100,637 | $ 111,965 | $ 116,029 | $ 122,886 | $ 135,733 |
| **Transmission** | | | | | | | | | |
| Transmission | 11,363 | 11,552 | 11,699 | 12,163 | 14,120 | 14,317 | 14,337 | 14,496 | 16,533 |
| Amortization of Contributions | (1,655) | (1,655) | (1,671) | (1,683) | (1,631) | (1,638) | (1,639) | (1,640) | (1,640) |
| | $ 9,708 | $ 9,897 | $ 10,028 | $ 10,480 | $ 12,489 | $ 12,680 | $ 12,698 | $ 12,856 | $ 14,893 |
| **Stations** | | | | | | | | | |
| Substations | 56,454 | 58,382 | 61,010 | 62,980 | 70,616 | 72,512 | 73,985 | 76,510 | 83,226 |
| Transformers | 2,463 | 2,667 | 7,070 | 6,102 | 3,681 | 2,288 | 1,829 | 1,749 | 1,813 |
| Amortization of Contributions | (1,159) | (1,169) | (1,230) | (1,186) | (1,461) | (1,462) | (1,463) | (1,466) | (1,469) |
| | $ 57,758 | $ 59,880 | $ 66,850 | $ 67,896 | $ 72,836 | $ 73,338 | $ 74,352 | $ 76,793 | $ 83,570 |
| **Distribution** | | | | | | | | | |
| Subtransmission Lines | 6,791 | 7,128 | 7,329 | 7,682 | 8,905 | 9,166 | 9,192 | 9,417 | 9,730 |
| Distribution Lines | 65,509 | 69,733 | 73,784 | 77,580 | 72,410 | 77,730 | 80,856 | 85,067 | 90,054 |
| Meters & Transformers | 1,309 | 1,343 | 1,358 | 1,435 | 1,551 | 1,597 | 2,033 | 2,027 | 2,242 |
| Amortization of Contributions | (8,052) | (8,315) | (8,582) | (8,891) | (9,769) | (10,180) | (10,613) | (10,812) | (11,117) |
| | $ 65,557 | $ 69,889 | $ 73,889 | $ 77,806 | $ 73,097 | $ 78,312 | $ 81,468 | $ 85,699 | $ 90,909 |
| **Other** | | | | | | | | | |
| Communications | 9,837 | 12,910 | 12,634 | 13,591 | 17,636 | 19,473 | 21,235 | 22,952 | 24,521 |
| Motor Vehicles | 6,555 | 7,169 | 7,879 | 8,324 | 8,275 | 8,691 | 9,290 | 9,692 | 10,236 |
| Structures & Improvements | 3,033 | 2,863 | 3,239 | 3,380 | 3,216 | 5,614 | 6,543 | 6,785 | 7,363 |
| General Equipment | 21,173 | 21,310 | 19,180 | 18,555 | 20,572 | 19,118 | 18,356 | 18,898 | 20,273 |
| Computer Development | 11,250 | 12,624 | 13,119 | 15,198 | 13,582 | 13,352 | 15,553 | 16,099 | 16,616 |
| Affordable Energy Fund | 0 | 0 | 0 | 875 | 625 | 1,441 | 10,108 | 12,101 | 3,658 |
| Miscellaneous | 3,902 | 4,185 | 3,899 | 4,596 | 2,701 | 4,067 | 4,309 | 3,615 | 1,080 |
| Corporate Allocation | (1,779) | (1,694) | (1,661) | (1,520) | (2,093) | (2,012) | (2,139) | (2,135) | (2,136) |
| | $ 53,971 | $ 59,367 | $ 58,289 | $ 62,999 | $ 64,514 | $ 69,745 | $ 83,254 | $ 88,007 | $ 81,611 |
| **Total Depreciation and Amortization Expense** | $ 274,325 | $ 289,290 | $ 301,213 | $ 310,915 | $ 323,573 | $ 346,039 | $ 367,801 | $ 386,242 | $ 406,717 |

# 24

**PUB/MH II-14**

**Subject:** **Tab 4 Financial Results & Forecast**
**Reference:** **PUB/MH I-24 Payments to Province**

**a) Please confirm that MH's payments to the province totaled:**

| | | |
|---|---|---|
| **F2005** | **$228 M** | **(15% of Gross Revenue)** |
| **F2006** | **$215 M** | **(11% of Gross Revenue)** |
| **F2007** | **$221 M** | **(13% of Gross Revenue)** |
| **F2008** | **$247 M** | **(14% of Gross Revenue)** |
| **F2009** | **$239 M** | **(13% of Gross Revenue)** |
| **F2010 Forecast** | **$230 M** | **(14% of Gross Revenue)** |
| **F2015 Forecast** | **$275 M** | **(14% of Gross Revenue)** |
| **F2020 Forecast** | **$380 M** | **(13% of Gross Revenue)** |

**ANSWER:**

Payments to the Province exclude municipal GILT and business taxes. The revised table is as follows.

| | | |
|---|---|---|
| F2005 | $228 M | (15% of Gross Revenue) |
| F2006 | $235 M | (13% of Gross Revenue) |
| F2007 | $221 M | (14% of Gross Revenue) |
| F2008 | $237 M | (14% of Gross Revenue) |
| F2009 | $239 M | (14% of Gross Revenue) |
| F2010 Forecast | $240 M | (15% of Gross Revenue) |
| F2015 Forecast | $275 M | (13% of Gross Revenue) |
| F2020 Forecast | $380 M | (13% of Gross Revenue) |

**PUB/MH I-24**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 21 & 22 of 29 Payments to Governments**

a) **Please provide a schedule that details all payments to municipalities and the Province by year for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.**

**ANSWER:**

Please see the attached schedule for all payments to municipalities and the Province for 2005 through 2012.

**Payments to the Province and Municipalities (Millions)**

| Fiscal Year Ended | Water Rentals | Provincial Guarantee Fee | Sinking Fund Admin. Fee | Capital Taxes | Payroll Taxes | Provincial Mitigation or Settlement Obligations (1) | Municipal GILT and Business Taxes | Gross Electricity Operations Revenue | Gross Export Revenue |
|---|---|---|---|---|---|---|---|---|---|
| 2005 | $ 104 | $ 68 | $ 1 | $ 35 | $ 7 | $ 13 | $ 10 | $ 1,508 | $ 554 |
| 2006 | 124 | 66 | 0 | 36 | 7 | 2 | 10 | 1,828 | 827 |
| 2007 | 106 | 68 | 0 | 37 | 8 | 2 | 10 | 1,632 | 592 |
| 2008 | 117 | 70 | 1 | 39 | 8 | 2 | 11 | 1,707 | 625 |
| 2009 | 115 | 70 | 1 | 44 | 9 | 0 | 11 | 1,765 | 623 |
| 2010 | 111 | 72 | 1 | 45 | 9 | 2 | 15 | 1,581 | 414 |
| 2011 | 102 | 78 | 0 | 47 | 9 | 8 | 15 | 1,584 | 383 |
| 2012 | 100 | 83 | 0 | 48 | 9 | 0 | 15 | 1,808 | 554 |
| 2013 | 103 | 89 | 0 | 50 | 10 | 1 | 15 | 1,895 | 583 |
| 2014 | 104 | 93 | 0 | 55 | 10 | 0 | 16 | 1,987 | 615 |
| 2015 | 103 | 101 | 0 | 61 | 10 | 0 | 16 | 2,039 | 590 |
| 2016 | 103 | 114 | 0 | 69 | 10 | 0 | 16 | 2,219 | 701 |
| 2017 | 104 | 131 | 0 | 77 | 10 | 0 | 17 | 2,320 | 729 |
| 2018 | 103 | 147 | 0 | 82 | 11 | 0 | 17 | 2,404 | 742 |
| 2019 | 103 | 159 | 1 | 88 | 11 | 0 | 17 | 2,628 | 894 |
| 2020 | 112 | 166 | 0 | 91 | 11 | 0 | 18 | 2,907 | 1,093 |

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $11 million remain to be paid in fiscal 2010 and future years.

## PUB/MH I-24

**Subject:** Tab 4: Financial Results & Forecast
**Reference:** Tab 4 Page 21 & 22 of 29 Payments to Governments

b) **Please provide a schedule that details the calculation of the debt guarantee fee for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.**

## ANSWER:

**PUB/MH I - 24(b)**

Provincial Debt Guarantee Fee Calculations
($ millions)

| | Actual 2005 (1) | Actual 2006 (1) | Actual 2007 (1) | Actual 2008 (1) | Actual 2009 (1) | Actual 2010 (1) (2) | Forecast 2011 (3) | Forecast 2012 (3) |
|---|---|---|---|---|---|---|---|---|
| Long Term Debt Balance | 7,311 | 7,141 | 7,108 | 7,160 | 7,486 | 8,132 | 8,104 | 8,623 |
| Short Term Debt Balance | 94 | 59 | - | 148 | - | 100 | 48 | 40 |
| Trust Investment from Pre-Financing | | | | | (122) | (166) | | |
| PDGF Assessed On | 7,405 | 7,200 | 7,108 | 7,308 | 7,364 | 8,066 | 8,152 | 8,663 |
| Guarantee Fee Rate | 0.95% | 0.95% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% |
| Amount Paid to Province | 70 | 68 | 71 | 73 | 74 | 76 | 82 | 87 |
| Portion Allocated to Centra | (3) | (3) | (3) | (3) | (3) | (3) | (3) | (4) |
| Net Hydro Guarantee Fee | 68 | 66 | 68 | 70 | 70 | 72 | 78 | 83 |

Notes:
(1) The fee calculation is based on ending debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in PUB 24(b) represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.
(2) The PDGF on US debt is paid in US dollars using the stated PDGF rate. For presentation purposes, US debt balances are translated to a Canadian equivalent using the year end exchange rate. The presentation of the US long term debt balance at March 31, 2009 was translated at the year end exchange rate of 1.2602 although the US dollar PDGF payment was made at a 1.05036 exchange rate utilizing FX forward contracts. Therefore, the Canadian equivalent of the amount paid to the Province for this year is less than 1%.
(3) US Dollar long term debt balance converted at forecast year end rate of 1.06 at March 31, 2010 for 2011 and US Dollar long term debt balance converted at forecast year end rate of 1.07 at March 31, 2011 for 2012.

**PUB/MH I-24**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 21 & 22 of 29 Payments to Governments**

**c) Please provide a schedule that details the calculation of water rental payments for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.**

**ANSWER:**

Please see the following schedule for the water rental payment calculation for the years 2005 through 2012.

**Water Rental Calculation**

| | Actual 2005 | Actual 2006 | Actual 2007 | Actual 2008 | Actual 2009 | Forecast 2010 | Forecast 2011 | Forecast 2012 | |
|---|---|---|---|---|---|---|---|---|---|
| Megawatt-Hours Generated (million mWh) | 31.1 | 37.2 | 31.6 | 34.9 | 34.2 | 33.1 | 30.5 | 30.1 | |
| Converted to Horsepower-years | 5.1 | 6.1 | 5.2 | 5.7 | 5.6 | 5.4 | 5.0 | 4.9 | (1) |
| Rental Rate per Horsepower-year | 20.32 | 20.32 | 20.32 | 20.32 | 20.32 | 20.32 | 20.32 | 20.32 | (2) |
| Calculated Water Annual Rental ($ million) | $ 104.1 | $ 124.4 | $ 105.7 | $ 116.7 | $ 114.3 | $ 110.7 | $ 102.0 | $ 100.5 | |
| Minimum Rental Adjustment | | | | | 0.2 | 0.5 | 0.3 | | (3) |
| Other Adjustment | | | | 0.3 | | | | | (4) |
| Total Water Rentals | $ 104.1 | $ 124.4 | $ 105.7 | $ 117.0 | $ 114.5 | $ 111.2 | $ 102.3 | $ 100.5 | |

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally , the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as 2009 it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Due to a rounding difference.

*2010/11 Forecast vs 2011/12 Forecast*

Total Capital and Other Taxes are expected to increase moderately in line with corporate growth.

Please see the following schedule for a breakdown of Capital and Other Taxes.

**MANITOBA HYDRO**
**CAPITAL AND OTHER TAXES**

**Schedule 4.10.0**
**(000's)**

| | 2007/08 Actual | 2008/09 Actual | 2009/10 Forecast | 2010/11 Forecast | 2011/12 Forecast |
|---|---|---|---|---|---|
| Capital Tax | $ 38,353 | $ 44,303 | $ 44,627 | $ 47,272 | $ 47,899 |
| Grants in Lieu of Taxes | 9,332 | 9,324 | 12,828 | 12,897 | 13,155 |
| Payroll Tax | 8,121 | 8,979 | 9,075 | 9,257 | 9,442 |
| Business & Property Tax | 1,346 | 1,202 | 1,851 | 1,845 | 1,881 |
| Other Municipal Payments | - | - | 4,500 | 4,500 | 4,500 |
| **Total Capital and Other Taxes** | $ 57,152 | $ 63,808 | $ 72,881 | $ 75,771 | $ 76,877 |

**PUB/MH I-41**

**Subject:** **Tab 4: Financial Results & Forecast**
**Reference:** **Tab 4 Page 25 of 29 Capital Tax**

**Please provide the details of the taxable paid up capital balance for Manitoba capital tax purposes for the fiscal years 2008, 2009 and the projected taxable capital for the fiscal years 2010 through 2012.**

**ANSWER:**

Please see the following table for capital tax information for the years 2008 through 2012.

**Taxable Paid Up Capital Calculation:**
**($ Billions)**

| | Actual 2008 | Actual 2009 | Forecast 2010 | Forecast 2011 | Forecast 2012 |
|---|---|---|---|---|---|
| Total Debt | 7.8 | 8.5 | 8.4 | 8.9 | 9.5 |
| Retained Earnings | 1.8 | 2.1 | 2.2 | 2.3 | 2.3 |
| AOCI | 0.3 | -0.2 | 0.2 | 0.2 | 0.1 |
| Total Paid Up Capital (A) | 9.9 | 10.5 | 10.7 | 11.3 | 11.9 |
| | | | | | |
| Temporary Investments | 0.1 | 0.2 | 0.0 | 0.0 | 0.0 |
| Sinking Fund Assets | 0.7 | 0.6 | 0.4 | 0.3 | 0.3 |
| Pension Investments | 0.8 | 0.6 | 0.7 | 0.7 | 0.8 |
| Investment in Subsidiaries | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Loans to Subsidiaries | 0.5 | 0.6 | 0.7 | 0.8 | 1.3 |
| Total Eligible Assets (B) | 2.4 | 2.3 | 2.0 | 2.1 | 2.6 |
| | | | | | |
| Total Assets (C) | 12.0 | 12.6 | 12.1 | 12.6 | 13.2 |
| | | | | | |
| Total Paid Up Capital | 9.9 | 10.5 | 10.7 | 11.3 | 11.9 |
| Less Investment Allowance (B/C X A) | 2.0 | 1.9 | 1.8 | 1.9 | 2.4 |
| | | | | | |
| Taxable Paid Up Capital | 8.0 | 8.6 | 8.9 | 9.5 | 9.6 |

**Capital Tax Calculation**
**($ millions)**

| | | | | | |
|---|---|---|---|---|---|
| Capital Tax at 0.5% X D | 40 | 43 | 45 | 47 | 48 |

# 25

**PUB/MH II-28**

**Subject:** **Tab 4 Financial Results & Forecast**
**Reference:** **Manitoba Hydro Taxes Collected from Customers**

a) **What amount in dollars is the City of Winnipeg requesting and does this amount include interest?**

**ANSWER:**

To date, the City of Winnipeg has issued formal assessment notices requesting $8.7 million, of which, $6.2 relates to Manitoba Hydro and $2.5 million to Centra. These dollars relate to the period of August 1, 1999 through to December 31, 2008. These amounts do not include interest.

In the Amended Statement of Claim filed by the City of Winnipeg with the Queen's Bench the period in question has been expanded to include the period from January 1, 1991 to the present. The City did not provide a dollar amount in their Amended Statement of Claim.