# EXHIBIT LIST

## A – ADMINISTRATIVE

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| A1 | 1 | 1 | Exhibit List | R. Bourke |
| | 2 | 1 | Application | R. Bourke |
| | 3 | 1 | List of Specific Approvals Requested | R. Bourke |
| | 4 | 1 | Draft Issues List | R. Bourke |
| | 5 | 1 | Procedural Orders / Motions / Correspondence | |
| | 6 | 1 | Accounting Orders | K. Culbert |
| | | 2 | Accounting for Rate Regulated Operations – Current and Future Changes | K. Culbert<br>J. Jozsa<br>B. Yuzwa |
| | 7 | 1 | List of Non-Compliance with Uniform System of Accounts and Reference to Accounting Orders | K. Culbert |
| | 8 | 1 | Map of Distribution System | R. Bourke |
| | 9 | 1 | List of Affiliate Transactions for the 2013 Test Year, 2012 Bridge Year and 2011 Historic Year | J. Jozsa<br>B. Yuzwa |
| | 10 | 1 | Utility Organization Charts | R. Bourke<br>S. Trozzi |
| | 11 | 1 | Corporate Organization Charts | R. Bourke<br>J. Jozsa |

# EXHIBIT LIST

## A – ADMINISTRATIVE

| Exhibit | Tab | Schedule | Contents | Witness(es) | |
|---|---|---|---|---|---|
| A1 | 12 | 1 | Planned Changes in Corporate or Operational Structure | J. Jozsa<br>B. Yuzwa | |
| | 13 | 1 | Status of Board Directives from Previous Board Decisions and / or Orders | R. Bourke | |
| | 14 | 1 | Conditions of Service | T. Ferguson<br>S. McGill | |
| | | 2 | Changes to the Schedule of Service Charges - Rider G | S. McGill<br>M. Torriano | |
| | 15 | 1 | Curriculum Vitae of Company Witnesses | R. Bourke | |
| | | 2 | Curriculum Vitae of Manuel Monteiro | R. Bourke | |
| | | 3 | Curriculum Vitae of Company Witnesses | R. Bourke | |
| | | 4 | Curriculum Vitae of Dr. Rebecca Honeyfield | R. Bourke | |
| | | 5 | Curriculum Vitae of Steven A. Fenrick and Lullit Getachew | R. Bourke | /u |

## A2 - Overview

| | | | | | |
|---|---|---|---|---|---|
| A2 | 1 | 1 | Summary of Application | R. Bourke | |
| | | 2 | Concentric Study - Benchmarking Study | J. Coyne<br>J. Lieberman<br>Concentric | |

# EXHIBIT LIST

## A – ADMINISTRATIVE

| Exhibit | Tab | Schedule | Contents | Witness(es) | |
|---|---|---|---|---|---|
| A2 | 1 | 3 | PSE - Productivity Study | S. Fenrick<br>L. Getachew<br>PSE | /u |
| | 2 | 1 | 2013 Regulatory Budget Assumptions and Guidelines Directive | S. Kancharla<br>R. Lei | |
| | | 2 | Budget Process Flowchart | S. Kancharla<br>R. Lei | |
| | | 3 | Approval Process | S. Kancharla<br>R. Lei | |
| | 3 | 1 | Changes in Methodology - Other Post - Employment Benefits | K. Culbert<br>J. Jozsa | |
| | | 2 | Changes in Methodology - Pension Expense | K. Culbert<br>J. Jozsa<br>S. Kancharla<br>A. Patel<br>B. Yuzwa | |
| | 4 | 1 | Drivers of Sufficiency/Deficiency | K. Culbert | |
| A3 - Finance | | | | | |
| A3 | 1 | 1 | Interim Financial Statements - Enbridge Gas Distribution - 2011 Historic Year | J. Jozsa<br>B. Yuzwa | |
| | | 2 | Interim Financial Statements - Enbridge Inc. - 2011 Historic Year | J. Jozsa<br>S. Kancharla<br>B. Yuzwa | |
| | 2 | 1 | Financial Statements - Utility Proforma Statements for Bridge and Test Year | K. Culbert | |

# EXHIBIT LIST

## A – ADMINISTRATIVE

| Exhibit | Tab | Schedule | Contents | Witness(es) | |
|---|---|---|---|---|---|
| A3 | 3 | 1 | Financial Statements – Enbridge Gas Distribution Historic 2010 Year | J. Jozsa<br>B. Yuzwa | |
| | 4 | 1 | Annual Report (Actual) and Management Discussion and Analysis (MD&A) – Enbridge Gas Distribution Historic 2010 Year | J. Jozsa<br>B. Yuzwa | |
| | | 2 | Annual Report (Actual) and Management Discussion and Analysis (MD&A) – Enbridge Gas Distribution Historic 2011 Year | J. Jozsa<br>B. Yuzwa | /u |
| | 5 | 1 | Reconciliation of Utility Income to Audited EGDI Consolidated Income 2011 Historic Year | K. Culbert | |
| | 6 | 1 | Annual / Audited Financial Reports (Historic) Enbridge Inc. – 2010 Year | J. Jozsa<br>B. Yuzwa | |
| | | 2 | Annual / Audited Financial Reports (Historic) Enbridge Inc. – 2011 Year | J. Jozsa<br>B. Yuzwa | /u |
| | 7 | 1 | Applicant Subsidiaries | J. Jozsa<br>B. Yuzwa | |
| | 8 | 1 | 10-K Filing – Parent Companies | J. Jozsa<br>B. Yuzwa | |
| | 9 | 1 | DBRS and S&P Reports | J. Jozsa<br>B. Yuzwa | |
| | 10 | 1 | Prospectus and Information Circulars | J. Jozsa<br>B. Yuzwa | |

# EXHIBIT LIST

## B – RATE BASE

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **B1 - Written Evidence** | | | | |
| B1 | 1 | 1 | Rate Base Evidence and Summaries | K. Culbert |
| | | 2 | Rate Base - Year to Year Summary | K. Culbert |
| | 2 | 1 | Rate Base - Capital Budget | L. Au<br>S. Kancharla<br>D. Kelly<br>R. Lei |
| | | 2 | Details of Capital Expenditures and Justification for Major Capital Projects over $500,000 - 2011 through 2013 | L. Au<br>D. Kelly<br>R. Lei |
| | | 3 | Comparison of Capital Expenditures by Year | L. Au<br>D. Kelly<br>R. Lei |
| | 3 | 1 | Asset Plan | L. Chiotti<br>L. Lawler /c |
| | | 2 | Asset Plan and 2013 Capital Budget | L. Chiotti<br>L. Lawler |
| | | 3 | Leave to Construct Projects | E. Chin<br>N. MacNeil |
| | 4 | 1 | Information Technology Capital Budget | B. Misra<br>H. Wong |
| | 5 | 1 | Storage Capital Expenditure | B. Pilon |

# EXHIBIT LIST

## B – RATE BASE

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Special Studies and Reports** | | | | |
| B2 | 1 | 1 | Economic Feasibility Procedure and Policy | F. Ahmad<br>P. Squires |
| | 2 | 1 | 2012 - 2021 Asset Plan | L. Chiotti<br>L. Lawler |
| **Test Year** | | | | |
| B3 | 1 | 1 | Ontario Utility Rate Base – Comparison of 2013 Test Year to 2012 Bridge Year | K. Culbert |
| | | 2 | Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2013 Test Year | K. Culbert |
| | | 3 | Working Capital Components of Average of Monthly Averages 2013 Test Year | K. Culbert |
| | 2 | 1 | Utility Capital Expenditures Comparison 2013 Test Year and 2012 Estimate | L. Au<br>D. Kelly<br>R. Lei |
| | | 2 | 2013 Capital Expenditures by Project (Projects Exceeding $500,000) | L. Au<br>D. Kelly<br>R. Lei |
| | | 3 | Gross Customer Additions and Average Cost per Customer Addition Budget 2013 and 2012 Estimate | F. Ahmad<br>L. Au<br>D. Kelly |
| | | 4 | System Expansion Monitoring - 2013 Test Year | F. Ahmad<br>P. Squires |

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# EXHIBIT LIST

## B – RATE BASE

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Bridge Year** | | | | |
| B4 | 1 | 1 | Ontario Utility Rate Base Comparison of 2012 Bridge Year to 2011 Historic Year | K. Culbert |
| | | 2 | Property, Plant, and Equipment Summary Statement – Average of Monthly Averages 2012 Bridge Year | K. Culbert |
| | | 3 | Working Capital Components of Average of Monthly Averages 2012 Bridge Year | K. Culbert |
| | 2 | 1 | Comparison of Utility Capital Expenditures 2012 Estimate and 2011 Historic | L. Au<br>D. Kelly<br>R. Lei |
| | | 2 | 2012 Capital Expenditures by Project (Projects Exceeding $500,000) | L. Au<br>D. Kelly<br>R. Lei |
| | | 3 | Gross Customer Additions and Average Cost per Customer Addition 2012 Estimate and 2011 Historic | F. Ahmad<br>L. Au<br>D. Kelly |
| | | 4 | System Expansion Monitoring 2012 Bridge Year | F. Ahmad<br>P. Squires |
| **Historic Year & Trend Data** | | | | |
| B5 | 1 | 1 | Ontario Utility Rate Base Comparison of 2011 Historic to 2007 Board Approved | K. Culbert |

# EXHIBIT LIST

## B – RATE BASE

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| B5 | 1 | 2 | Property, Plant, and Equipment Summary Statement - Average of Monthly Averages 2011 Historic | K. Culbert |
| | | 3 | Working Capital Components of Average of Monthly Averages 2011 Historic | K. Culbert |
| | 2 | 1 | Comparison of Utility Capital Expenditures 2011 Historic and 2007 Board Approved | L. Au<br>D. Kelly<br>R. Lei |
| | | 2 | 2011 Capital Expenditures by Project (Projects Exceeding $500,000) | L. Au<br>D. Kelly<br>R. Lei |
| | | 3 | Gross Customer Additions and Average Cost per Customer Addition Actual 2011 and 2011 Board Approved | F. Ahmad<br>L. Au<br>D. Kelly |
| | | 4 | System Expansion Portfolio - 2011 Historic | F. Ahmad<br>P. Squires |

# EXHIBIT LIST

## C – OPERATING REVENUE

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| **Written Evidence** | | | | |
| C1 | 1 | 1 | Operating Revenue Summary | K. Culbert |
| | 2 | 1 | Revenue Forecast | R. Lei<br>S. Qian |
| | 3 | 1 | Gas Volume Budget | R. Lei<br>S. Qian |
| | | 2 | Updated Gas Volume Budget | R. Lei<br>S. Qian |
| | 4 | 1 | Transactional Services | J. Denomy<br>V. Krauchek |
| | 5 | 1 | Other Service and Late Payment Penalty Revenue | S. McGill<br>M. Torriano |
| **Special Studies and Reports** | | | | |
| C2 | 1 | 1 | Key Economic Assumptions | H. Sayyan<br>M. Suarez |
| | 2 | 1 | Average Use Forecasting Model | H. Sayyan<br>M. Suarez |
| | 3 | 1 | Budget Degree Days | H. Sayyan<br>M. Suarez |
| | | 2 | Updated Budget Degree Days | H. Sayyan<br>M. Suarez |

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# EXHIBIT LIST

## C – OPERATING REVENUE

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| Test Year | | | | |
| C3 | 1 | 1 | Utility Operating Revenue 2013 Test Year | K. Culbert |
| | | 2 | Comparison of Utility Operating Revenue Budget 2013 and Estimate 2012 | R. Lei<br>S. Qian |
| | 2 | 1 | Customers, Volumes and Revenues by Rate Class - 2013 Budget | R. Lei<br>S. Qian |
| | | 2 | Comparison of Average Customer Numbers by Rate Class 2013 Budget and 2012 Estimate | R. Lei<br>S. Qian |
| | | 3 | Comparison of Gas Sales and Transportation Volume by Rate Class 2013 Budget and 2012 Estimate | R. Lei<br>S. Qian |
| | | 4 | Comparison of Gas Sales and Transportation Revenue by Rate Class 2013 Budget and 2012 Estimate | R. Lei<br>S. Qian |
| | 3 | 1 | Details of Other Revenue Budget 2013 and Estimate 2012 | R. Lei<br>S. Qian |
| | 4 | 1 | Transactional Services 2013 Test Year Budget Revenue and Cost Components | J. Denomy<br>V. Krauchek |
| | 5 | 1 | NGV Rate of Return 2013 Test Year | F. Ahmad<br>K. Culbert |

# EXHIBIT LIST

## C – OPERATING REVENUE

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| Bridge Year | | | | |
| C4 | 1 | 1 | Utility Operating Revenue 2012 Bridge Year | K. Culbert |
| | | 2 | Comparison of Utility Operating Revenue 2012 Estimate and 2011 Historic | R. Lei<br>S. Qian |
| | | 3 | Comparison of Utility Operating Revenue 2012 Estimate and Board 2007 Budget Approved | R. Lei<br>S. Qian |
| | 2 | 1 | Customers, Volumes and Revenues by Rate Class - 2012 Estimate | R. Lei<br>S. Qian |
| | | 2 | Comparison of Customer Numbers by Rate Class 2012 Estimate and 2011 Historic | R. Lei<br>S. Qian |
| | | 3 | Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2011 Historic | R. Lei<br>S. Qian |
| | | 4 | Comparison of Gas Sales and Transportation Revenue by Rate Class 2012 Estimate and 2011 Historic | R. Lei<br>S. Qian |
| | | 5 | Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2007 Board Approved | R. Lei<br>S. Qian |
| | 3 | 1 | Details of Other Revenue 2012 Estimate and 2011 Historic | R. Lei<br>S. Qian |

# EXHIBIT LIST

## C – OPERATING REVENUE

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| C4 | 3 | 2 | Details of Other Revenue 2012 Estimate and 2007 Board Approved | R. Lei<br>S. Qian |
| | 4 | 1 | Transactional Services 2012 Bridge Year Estimate vs. 2007 Board Approved Budget Revenue and Cost Components | V. Krauchek<br>J. Sarnovsky |
| | 5 | 1 | NGV Rate of Return 2012 Bridge Year | F. Ahmad<br>K. Culbert |
| **Historic Year and Trend Data** | | | | |
| C5 | 1 | 1 | Utility Operating Revenue 2011 Historic (Estimate) | K. Culbert |
| | | 2 | Comparison of Utility Operating Revenue 2011 Historic Year and 2007 Board Approved | R. Lei<br>S. Qian |
| | 2 | 1 | Customers, Volumes and Revenues by Rate Class –2011 Historic | R. Lei<br>S. Qian |
| | | 2 | Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2010 Historic | R. Lei<br>S. Qian |
| | | 3 | General Service System-Wide Normalized Average Use | R. Lei<br>S. Qian |
| | | 4 | Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2007 Board Approved | R. Lei<br>S. Qian |

# EXHIBIT LIST

## C – OPERATING REVENUE

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| C5 | 2 | 5 | General Service Average Uses Historical Normalized Actual and Board Approved Fiscal and Calendar Years | R. Lei<br>S. Qian |
| | | 6 | Large Volume (Contract) Customer Demand Historical Normalized Actual and Board Approved Fiscal and Calendar Years | R. Lei<br>S. Qian |
| | 3 | 1 | Details of Other Revenue 2011 Historic vs. 2007 Board Approved | R. Lei<br>S. Qian |
| | 4 | 1 | Transactional Services 2011 Historic vs. 2007 Board Approved Budget Revenue and Cost Components | J. Denomy<br>V. Krauchek |
| | 5 | 1 | NGV Rate of Return 2011 Historic Year | F. Ahmad<br>K. Culbert |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| Written Evidence | | | | |
| D1 | 1 | 1 | Operating Cost Summary | K. Culbert |
| | 2 | 1 | Gas Costs, Transportation and Storage | J. Sarnovsky<br>D. Small |
| | | 2 | Status of Transportation Contracts | J. Sarnovsky<br>D. Small |
| | | 3 | Design Criteria Evidence | J. Denomy<br>J. Sarnovsky |
| | | 4 | Curtailment Compliance Report | B. Manwaring |
| | 3 | 1 | Operating Maintenance Costs | S. Kancharla<br>R. Lei |
| | | 2 | Employee Expenses and Workforce Demographics | S. Trozzi |
| | 4 | 1 | Corporate Cost Allocation (“CAM”) | K. Culbert<br>J. Jozsa<br>B. Yuzwa |
| | | 2 | Updated Corporate Cost Allocation (“CAM”) | K. Culbert<br>J. Jozsa<br>B. Yuzwa |
| | 5 | 1 | Depreciation Rate Change | L. Au<br>J. Jozsa<br>D. Kelly |
| | 6 | 1 | Municipal Taxes | B. Remington |

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# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| D1 | 7 | 1 | Demand Side Management Budget | A. Mandyam |
| | 8 | 1 | Deferral and Variance Accounts | K. Culbert<br>R. Small |
| | | 2 | Not Used | |
| | | 3 | Deferral and Variance Account Forecast Balances | K. Culbert |
| | 9 | 1 | Open Bill Access | K. Lakatos-Hayward<br>S. McGill |
| | 10 | 1 | Finance Department - O&M Budget | J. Jozsa<br>S. Kancharla<br>R. Lei |
| | 11 | 1 | Not Used | |
| | 12 | 1 | CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the ADR Settlement in EB-2011-0226 | K. Culbert<br>K. Lakatos-Hayward<br>S. McGill |
| | | 2 | EB-2011-0226 Settlement Agreement Enbridge Customer Care and CIS Costs 2013 to 2018 - September 2, 2011 | K. Lakatos-Hayward<br>S. McGill |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| D1 | 13 | 1 | Energy Supply, Storage Development and Regulatory – O&M Budget | K. Culbert<br>B. Pilon<br>J. Sarnovsky<br>R. Small |
| | 14 | 1 | Law Department – O&M Budget | |
| | 15 | 1 | Operations – O&M Budget | W. Akkermans<br>J. Alton<br>D. Lapp<br>J. Sanders |
| | 16 | 1 | Information Technology – O&M Budget | T. Adesipo<br>B. Misra<br>H. Wong |
| | 17 | 1 | Business Development and Corporate Strategy | L. Kennedy<br>P. Squires |
| | 18 | 1 | Human Resources – O&M Budget | S. Trozzi |
| | 19 | 1 | Not Used | |
| | 20 | 1 | Pipeline Integrity and Safety – O&M Budget | J. Briggs<br>C. Hanlon<br>L. Lawler |
| | 21 | 1 | Public and Government Affairs – O&M Budget | C. Meyer<br>M. Sousa |
| | 22 | 1 | Non Departmental Expenses – O&M Budget | S. Trozzi |

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# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness | |
|---|---|---|---|---|---|
| D1 | 23 | 1 | Not Used | | |
| | 24 | 1 | Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM | K. Culbert<br>J. Jozsa<br>B. Yuzwa | |
| | | 2 | Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM | K. Culbert<br>J. Jozsa<br>B. Yuzwa | /u |
| | 25 | 1 | Service Quality Requirements (“SQR’s”) | T. Ferguson<br>K. Lakatos-Hayward<br>M. Torriano<br>M. Wagle | |
| Special Studies and Reports | | | | | |
| D2 | 1 | 1 | Regulatory Corporate Cost Allocation (“RCAM”) Update | J. Hails<br>MNP LLP | /u |
| | 2 | 1 | Depreciation Study | J. Spanos<br>Gannett Fleming | |
| | | 2 | Schedule Depreciation Rates | L. Au<br>D. Kelly<br>J. Jozsa | |
| | 3 | 1 | Compensation Study – A Comparison of the EGDI Compensation Program | Mercers Consultant | |
| | 4 | 1 | Gas System Design Criteria Analysis For Enbridge Gas Distribution | R. Honeyfield<br>Navigant Consultant | |
| | | 2 | Analysis of Peak Gas Day Design Criteria | R. Honeyfield<br>Navigant Consultant | |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness | |
|---|---|---|---|---|---|
| D2 | 5 | 1 | Regulated Unregulated Storage Cost Allocation | R. Feingold<br>Black & Veatch | |
| | 6 | 1 | Unaccounted For Gas Study | I. Chan | |
| | 7 | 1 | IFRS - *Benchmarking Conversion Costs* Including US-GAAP Implementation | M. Picard<br>KPMG | |
| | | 2 | Review of Enbridge Gas Distribution Overhead Allocations for IFRS March 5, 2010 | E. Rawlinson<br>Ernest & Young | |
| | 8 | 1 | 2011 Distributed Energy, Green Energy Initiatives and Fuel Cells Activities | T. Maclean | /c |
| | 9 | 1 | EB-2011-0008 - 2010 Earnings Sharing Mechanism Settlement Agreement - June 28, 2011 | R. Bourke | /c |
| | 10 | 1 | EB-2007-0615 - 2008 to 2012 IR Settlement Agreement - February 4, 2008 | R. Bourke | |
| Test Year | | | | | |
| D3 | 1 | 1 | Cost of Service 2013 Test Year | K. Culbert | |
| | 2 | 1 | Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012 | S. Kancharla<br>R. Lei | |
| | | 2 | Operating and Maintenance Expense by Department 2013 Test Year | S. Kancharla<br>R. Lei | |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness | |
|---|---|---|---|---|---|
| D3 | 2 | 3 | Operating and Maintenance Expense by Cost Type - 2013 Test Year vs. 2012 Bridge Year | S. Kancharla<br>R. Lei | |
| | | 4 | Salaries and Wages and FTE Forecast 2013 Test Year | S. Kancharla<br>R. Lei<br>S. Trozzi | |
| | 3 | 1 | Summary of Gas Cost to Operations | J. Sarnovsky<br>D. Small | |
| | | 2 | Summary of Storage and Transportation Costs Fiscal 2013 | J. Sarnovsky<br>D. Small | |
| | | 3 | Peak Day Supply Mix | J. Sarnovsky<br>D. Small | |
| | | 4 | Monthly Pricing Information | J. Sarnovsky<br>D. Small | |
| | | 5 | Gas Supply/Demand | J. Sarnovsky<br>D. Small | |
| | 4 | 1 | Unbilled and Unaccounted-for Gas Volumes | H. Sayyan<br>M. Suarez | /u |
| Bridge Year | | | | | |
| D4 | 1 | 1 | Cost of Service 2012 Bridge Year | K. Culbert | |
| | 2 | 1 | Cost of Service Comparison of Utility Costs and Expenses 2012 Estimate and 2011 Historic | S. Kancharla<br>R. Lei | |
| | | 2 | Not Used | | |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness | |
|---|---|---|---|---|---|
| D4 | 2 | 3 | Operating and Maintenance Expense by Department 2012 Estimate | S. Kancharla<br>R. Lei | |
| | | 4 | Operating and Maintenance Expense by Cost Type 2012 Estimate and 2011 Historic | S. Kancharla<br>R. Lei | |
| | | 5 | Salaries and Wages and FTE Estimate 2012 Bridge Year | S. Kancharla<br>R. Lei<br>S. Trozzi | |
| | 3 | 1 | Summary of Gas Cost to Operations 2012 Bridge Year | J. Sarnovsky<br>D. Small | |
| | | 2 | Summary of Storage & Transportation Costs Fiscal 2012 | J. Sarnovsky<br>D. Small | |
| | | 3 | Peak Day Supply Mix – 2012 Forecast | J. Sarnovsky<br>D. Small | |
| | 4 | 1 | Unbilled and Unaccounted-for Gas Volumes | H. Sayyan<br>M. Suarez | /u |

## Historic Year and Trend Data

| | | | | | |
|---|---|---|---|---|---|
| D5 | 1 | 1 | Cost of Service 2011 Historic | K. Culbert | |
| | 2 | 1 | Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved | S. Kancharla<br>R. Lei | |
| | | 2 | Operating and Maintenance Expense by Department 2011 Historic | S. Kancharla<br>R. Lei | |

# EXHIBIT LIST

## D – OPERATING COST

| Exhibit | Tab | Schedule | Contents | Witness | |
|---|---|---|---|---|---|
| D5 | 2 | 3 | Operating and Maintenance Expense by Cost Type 2011 Historic and 2007 Board Approved | S. Kancharla<br>R. Lei | |
| | | 4 | Salaries and Wages and FTE 2011 Historic | S. Kancharla<br>R. Lei<br>S. Trozzi | |
| | | 5 | O&M Variances 2007 - 2011 | S. Kancharla<br>R. Lei | |
| | 3 | 1 | Summary of Gas Cost to Operations 2011 Historic Year | J. Sarnovsky<br>D. Small | |
| | | 2 | Summary of Storage & Transportation Costs Fiscal 2011 Historic | J. Sarnovsky<br>D. Small | |
| | | 3 | Canadian Peak Day Supply Mix 2011 Historic | J. Sarnovsky<br>D. Small | |
| | 4 | 1 | Unbilled and Unaccounted-for Volumes 2011 Historic vs. 2007 Board Approved | H. Sayyan<br>M. Suarez | /u |

# EXHIBIT LIST

## E – COST OF CAPITAL

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Written Evidence** | | | | |
| E1 | 1 | 1 | Cost of Capital Summary | K. Culbert |
| | 2 | 1 | Cost of Capital | D. Yaworsky |
| **Special Studies and Reports** | | | | |
| E2 | 1 | 1 | Return on Equity Calculation for 2013 | R. Fischer<br>M. Lister<br>S. Murray |
| | | 2 | Capital Structure: Equity Ratio | R. Fischer<br>M. Lister<br>D. Yaworsky |
| | 2 | 1 | Concentric Energy Advisors : Equity Thickness Evaluation & Recommendation | J. Coyne<br>J. Lieberman<br>Concentric |
| **Test Year** | | | | |
| E3 | 1 | 1 | Revenue Deficiency Calculation And Required Rate Of Return 2013 Test Year | K. Culbert |
| | | 2 | Summary Statement of Principal and Carrying Costs of Term Debt 2013 Test Year | K. Culbert |
| | | 3 | Unamortized Debt Discount and Expense Average of Monthly Averages 2013 Test Year | K. Culbert |
| | | 4 | Preference Shares Summary Statement of Principal and Carrying Cost 2013 Test Year | K. Culbert |

# EXHIBIT LIST

## E – COST OF CAPITAL

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| E3 | 1 | 5 | Unamortized Preference Share Issue Expense Average of Monthly Averages 2013 Test Year | K. Culbert |
| **Bridge Year** | | | | |
| E4 | 1 | 1 | Cost of Capital 2012 Bridge Year | K. Culbert |
| | | 2 | Summary Statement of Principal and Carrying Cost of Term Debt 2012 Bridge Year | K. Culbert |
| | | 3 | Unamortized Debt Discount and Expense Average of Monthly Averages 2012 Bridge Year | K. Culbert |
| | | 4 | Preference Shares Summary Statement of Principal and Carrying Cost 2012 Bridge Year | K. Culbert |
| | | 5 | Unamortized Preference Shares Issue Expense Average of Monthly Averages 2012 Bridge Year | K. Culbert |
| **Historic Year and Trend Data** | | | | |
| E5 | 1 | 1 | Revenue Sufficiency Calculation And Required Rate Of Return 2011 Historical Year (Estimate) | K. Culbert |
| | | 2 | Summary Statement of Principal and Carrying Cost of Term Debt 2011 Historic | K. Culbert |

# EXHIBIT LIST

## E – COST OF CAPITAL

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| E5 | 1 | 3 | Unamortized Debt Discount and Expense Average of Monthly Averages 2011 Historic | K. Culbert |
| | | 4 | Preference Shares Summary Statement of Principal and Carrying Cost 2011 Historic | K. Culbert |
| | | 5 | Unamortized Preference Share Issue Expense Average of Monthly Averages 2011 Historic | K. Culbert |

# EXHIBIT LIST

## F – REVENUE SUFFICIENCY/DEFICIENCY

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Written Evidence** | | | | |
| F1 | 1 | 1 | Revenue (Deficiency) / Sufficiency Summary | K. Culbert |
| **Test Year** | | | | |
| F3 | 1 | 1 | Cost of Capital 2013 Test Year | K. Culbert |
| | | 2 | Utility Income 2013 Test Year | K. Culbert |
| | | 3 | Utility Rate Base 2013 Test Year | K. Culbert |
| **Bridge Year** | | | | |
| F4 | 1 | 1 | Revenue Sufficiency Calculation and Required Rate of Return 2012 Bridge Year | K. Culbert |
| | | 2 | Utility Income 2012 Bridge Year | K. Culbert |
| | | 3 | Utility Rate Base 2012 Bridge Year | K. Culbert |
| **Historic Year and Trend Data** | | | | |
| F5 | 1 | 1 | Revenue Sufficiency and Recalculated Rate of Return 2011 Historic | K. Culbert |
| | | 2 | Utility Income 2011 Historic | K. Culbert |
| | | 3 | Utility Rate Base 2011 Historic | K. Culbert |

# EXHIBIT LIST

## G – COST ALLOCATION

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Written Evidence** | | | | |
| G1 | 1 | 1 | 2013 Cost Allocation Methodology | A. Kacicnik<br>M. Kirk |
| **Test Year** | | | | |
| G2 | 1 | 1 | Fully Allocated Cost Study - 2013 Test Year | A. Kacicnik<br>M. Kirk |
| | 2 | 1 | Revenue to Cost/Rate of Return Comparisons | A. Kacicnik<br>M. Kirk |
| | | 2 | Revenue to Cost/Rate of Return Comparisons Excluding Gas Supply Commodity | A. Kacicnik<br>M. Kirk |
| | 3 | 1 | Functionalization of Utility Rate Base | A. Kacicnik<br>M. Kirk |
| | | 2 | Functionalization of Utility Working Capital | A. Kacicnik<br>M. Kirk |
| | | 3 | Functionalization of Utility Net Investments | A. Kacicnik<br>M. Kirk |
| | | 4 | Functionalization of Utility O&M | A. Kacicnik<br>M. Kirk |
| | 4 | 1 | Classification of Rate Base | A. Kacicnik<br>M. Kirk |
| | | 2 | Classification of Net Investment | A. Kacicnik<br>M. Kirk |
| | | 3 | Classification of O&M Costs | A. Kacicnik<br>M. Kirk |

# EXHIBIT LIST

## G – COST ALLOCATION

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| G2 | 5 | 1 | Allocation of Rate Base | A. Kacicnik<br>M. Kirk |
| | | 2 | Allocation of Return & Taxes | A. Kacicnik<br>M. Kirk |
| | | 3 | Allocation of Total Cost of Service | A. Kacicnik<br>M. Kirk |
| | 6 | 1 | Rate Base Functionalization Factors | A. Kacicnik<br>M. Kirk |
| | | 2 | Classification of Gas Costs to Operations | A. Kacicnik<br>M. Kirk |
| | | 3 | Allocation Factors | A. Kacicnik<br>M. Kirk |
| | | 4 | Allocation of DSM Program Costs General Costs Including Fringe Benefits and A&G | A. Kacicnik<br>M. Kirk |
| | 7 | 1 | Tecumseh – Functionalization and Classification of Rate Base | A. Kacicnik<br>M. Kirk |
| | | 2 | Tecumseh – Functional Allocation of Cost of Service - 2013 Test Year | A. Kacicnik<br>M. Kirk |
| | | 3 | Tecumseh – Classification of Cost of Service 2013 Test Year | A. Kacicnik<br>M. Kirk |
| | | 4 | Tecumseh Gas Rate Derivation 2013 Test Year | A. Kacicnik<br>M. Kirk |

# EXHIBIT LIST

## G – COST ALLOCATION

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| G2 | 7 | 5 | Tecumseh Gas Isolation of Transmission Related Rate Base 2013 Test Year | A. Kacicnik<br>M. Kirk |
| | | 6 | Tecumseh Gas Isolation of Transmission Related Operating Cost 2013 Test Year | A. Kacicnik<br>M. Kirk |
| | | 7 | Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2013 Test Year | A. Kacicnik<br>M. Kirk |

# EXHIBIT LIST

## H – RATE DESIGN

| Exhibit | Tab | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| **Written Evidence** | | | | |
| H1 | 1 | 1 | 2013 Proposed Rates | J. Collier<br>A. Kacicnik |
| **Test Year** | | | | |
| H2 | 1 | 1 | Revenue Comparison – Current Revenue vs. Proposed Revenue | J. Collier |
| | 2 | 1 | Proposed Revenue Recovery by Rate Class | J. Collier |
| | 3 | 1 | Summary of Proposed Rate Change by Rate Class | J. Collier |
| | 4 | 1 | Calculation of Gas Supply Charges by Rate Class | J. Collier |
| | 5 | 1 | Detailed Revenue Calculations by Rate Class | J. Collier |
| | 6 | 1 | Rate Handbook | J. Collier |
| | 7 | 1 | Annual Bill Comparison | J. Collier |

# EXHIBIT LIST

## I - INTERROGATORIES and RESPONSES

| Exhibit | Issue | Schedule | Contents | Witness(es) |
|---|---|---|---|---|
| I | USGAAP | 1.1 to 1.7 | Board Staff | EGDI |
| | | 2.1 to 2.2 | APPrO | EGDI |
| | | 7.1 to 7.3 | Energy Probe | EGDI |

# EXHIBIT LIST

| Exhibit | Tab | Schedule | Contents | Witness |
|---|---|---|---|---|
| M1 | 1 | 1 | Impact Statement No. 1 | K. Culbert |
| | | 2 | Change in Revenue Requirement<br>2013 Test Year | K. Culbert |
| | | 3 | Utility Rate Base<br>2013 Test Year | K. Culbert |
| | | 4 | Utility Income<br>2013 Test Year | K. Culbert |
| | | 5 | Ontario Utility Capital Structure<br>2013 Test Year | K. Culbert |

**EB-2011-0354**

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Sched. B, as amended;

**AND IN THE MATTER OF** an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the sale, distribution, transmission, and storage of gas.

# A P P L I C A T I O N

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company"), is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge Gas Distribution hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act*, *1998* as amended (the "Act"), for an Order or Orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2013. For the purposes of subsection 36(3) of the Act, Enbridge Gas Distribution requests that the Board use the cost of service (or revenue requirement) method to approve or fix just and reasonable rates.

3. Through this Application, the Company requests that the Board approve new rates for 2013 that will: (a) implement certain prior decisions of the Board, and (b) effect a cost of service rebasing of Enbridge Gas Distribution's rates based on forecast 2013 costs.

4. In previous proceedings, the Board has already determined certain items that impact on Enbridge Gas Distribution's 2013 cost of service. In the EB-2009-0084 Report of the Board on the Cost of Capital for Regulated Utilities, the Board indicated that utilities could use the Board's new Return on Equity ("ROE") formula in their next cost of service filing. In the EB-2011-0226 proceeding, the Board approved a settlement agreement that fixed the amounts that Enbridge Gas Distribution may recover in rates for particular customer care services (including

its Customer Information System) for the years from 2013 to 2018. The Company has incorporated these Board-approved items in this cost of service application and requests approval of the implementation of these previously-approved items into 2013 rates. Compared to the amounts contained in the previous fiscal year's Board-approved revenue requirement, these items produce a distribution revenue deficiency of $31.4 million during the period between January 1, 2013 and December 31, 2013 (the "Test Year"). When the Company's rates are adjusted by the Board effective January 1, 2013 to permit the elimination of this distribution revenue deficiency, Enbridge Gas Distribution estimates that the amount charged to an average residential customer will increase by approximately $10 annually. This would result in an approximate 1.7 percent increase on a T-service basis (that is, total bill excluding commodity costs) or approximately 1.1 percent increase in the total annual bill (includes commodity costs).

5. Through this Application, the Company requests approval of a 2013 distribution revenue requirement based on its cost of service for the Test Year. If Enbridge Gas Distribution's currently effective rates remain in effect, with the only change being the implementation of the Board's previous decisions described in the paragraph above, then the Company forecasts at this time that it will realize a distribution revenue deficiency of approximately $59.9 million during Test Year. In the event that the Company's rates are adjusted by the Board effective January 1, 2013 to permit the elimination of this distribution revenue deficiency, the Company estimates that the amount charged to an average residential customer will increase by approximately $17 annually. This would result in an approximate 3.1 percent increase on a T-service basis (that is, total bill excluding commodity costs) or approximately 1.9 percent increase in the total annual bill (includes commodity costs).

6. Enbridge Gas Distribution applies to the Board for such final, interim or other Orders, accounting orders and deferral and variance accounts as may be necessary in relation to the approving or fixing of just and reasonable rates for the sale, distribution, transmission, and storage of gas in the Test Year, including:

i. approval of the implementation of the Board's determinations in the EB-2009-0084 (ROE) and EB-2011-0226 (customer care) proceedings into the Company's rates for the year commencing January 1, 2013;

ii. approval of all other aspects of the Company's requested distribution revenue requirement and associated deficiency to be recovered through the Company's rates for the year commencing January 1, 2013;

iii. approval of all other items set out at Exhibit A1, Tab 3, Schedule 1 of the Company's evidence ("Approvals Requested"); and

iv. the determination of all other issues that bear upon the Board's approval or fixing of just and reasonable rates for the sale, distribution, transmission and storage of gas by Enbridge Gas Distribution for the year commencing January 1, 2013.

7. In the event that a final rate Order in this proceeding will not be in place on January 1, 2013, the Company requests that interim rates be set and implemented as of January 1, 2013, and that final rates be set to be effective January 1, 2013 notwithstanding that the Board's Decision fixing these rates may not be delivered until after that date.

8. Enbridge Gas Distribution further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

9. The persons affected by this Application are the customers of Enbridge Gas Distribution. It is impractical to set out the names and addresses of the customers because they are too numerous.

10. Enbridge Gas Distribution requests that a copy of all documents filed with the Board by each party to this proceeding be served on the Applicant and the Applicant's counsel as follows:

Mr. Norm Ryckman
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.

| | |
|---|---|
| Address for personal service: | 500 Consumers Road<br>Willowdale, Ontario M2J 1P8 |
| Mailing address: | P.O. Box 650<br>Scarborough, Ontario M1K 5E3 |

Telephone: 416.495.5499 or 1.888.659.0685
Fax: 416-495-6072
E-mail: EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Address for personal service and mailing address: Brookfield Place, PO Box 754
Suite 1800, 181 Bay Street
Toronto, Ontario
M5J 2T9

Telephone: 416-865-7742
Fax: 416-863-1515
E-mail: fcass@airdberlis.com

Ms. Tania Persad
Enbridge Gas Distribution Inc.

Address for personal service: 500 Consumers Road
Willowdale, Ontario M2J 1P8

Mailing address: P.O. Box 650
Scarborough, Ontario M1K 5E3

Telephone: 416-495-5891
Fax: 416-495-5994
E-mail: tania.persad@enbridge.com

DATED January 31, 2012 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: [original signed]
Mr. Norm Ryckman

# LIST OF SPECIFIC APPROVALS REQUESTED

1. This application has two different purposes insofar as the approvals requested by the Company are concerned. The first purpose is to implement decisions or rulings made by the Board in other proceedings. The second purpose is to seek approval of other matters in relation to the 2013 cost of service rebasing of the Company's gas distribution rates.

2. In EB-2011-0226, the Board approved the annual revenue requirement for the Company's customer care and CIS services over the period from 2013 to 2018. Implementation of the Board's approval of the 2013 revenue requirement for customer care and CIS services results in an increment to the revenue requirement of $11 million over the comparable amount for 2012.

3. In EB-2009-0084, the Board approved a refined formula for the calculation of ROE and indicated that the new formula would be implemented in cost of service applications. The Company seeks approval of the implementation of the refined ROE formula in this case; which represents an increment to the 2013 revenue requirement of $20.4 million over 2012. Evidence in this regard is filed at Exhibit E2, Tab 1, Schedule 1.

4. The Company therefore seeks approval to change its final rates for the 2013 Test Year, effective January 1, 2013, to recover the distribution revenue deficiency of $31.4 million associated with implementation of decisions and rulings made by the Board in other proceedings. The Company also seeks approval to change its final rates for 2013 to recover the distribution revenue deficiency of $59.9 million associated with other matters that are part of the cost of service rebasing of its rates in 2013. Evidence regarding the revenue deficiency is filed at Exhibit A2, Tab 4, Schedule 1.

Witness: R. Bourke

5. The specific approvals sought by the Company for the purposes of the fixing or approval of 2013 gas distribution rates include the following:

   (a) Approval to adopt US GAAP for purpose of setting rates as described in evidence at Exhibit A1, Tab 6, Schedule 2.

   (b) Approval of the implementation of changes in methodology related to the accounting treatment of pensions and OPEB's as indicated in evidence at Exhibit A2, Tab 3, Schedules 1 and 2.

   (c) Approval of the Company's forecast of Budgeted Degree Days and the forecasting model to be utilized in each of the Company's three delivery areas, as found in evidence at Exhibit C2, Tab 3, Schedule 1.

   (d) Approval of the recommendation and conclusion in the Company's report on Unaccounted For ("UAF") gas volumes, found at Exhibit D2, Tab 6, Schedule 1, that the Company's approach to, and forecasting methods for, UAF continue to produce acceptable results, and that the submission of the UAF report satisfies the obligations undertaken by the Company in the Settlement Agreement in the 2010 ESM proceeding, docket EB-2011-0008.

   (e) Approval of the Company's proposed changes to the level of Transactional Services ("TS") revenue to be included in base rates, the change to the former guarantee of the base level of TS revenue to be included in rates and the proposed changes to the treatment of the deferral account(s) associated with TS revenue, as found in evidence at Exhibit C1, Tab 4, Schedule 1.

(f) Approval of the Company's proposed change to the Peak Gas Day Design Criteria ("PGDDC") for the 2013 Test Year as found in evidence at Exhibit D1, Tab 2, Schedule 3 and the proposed method for the recovery of the incremental cost impact of the implementation of the changes to the PGDDC using a deferral account, the Design Day Criteria Transportation Deferral Account ("DDCTDA") filed in evidence at Exhibit D1, Tab 8, Schedule1, with evidence filed in support of the Company's proposed change to the PGDDC submitted by Navigant Consulting, Inc., filed in evidence at Exhibit D2, Tab 4, Schedules 1 and 2.

(g) Approval for the Company's continued use of the RCAM methodology for the determination of the appropriate Utility expense related to the provision of services by its parent, Enbridge Inc., as revised to reflect the findings of the RCAM Study prepared by MNP LLP and contained in their report that will be filed in evidence at Exhibit D2, Tab 1, Schedule 1 when completed. The RCAM Study was a 2010 ESM Settlement Agreement obligation, now fulfilled.

(h) Approval of the Company's proposal related to its Open Bill Access ("OBA") programs for the continued provision of third party billing and bill insert activities, under the terms of the EB-2009-0043 Settlement Agreement, subject to an update of the costs and fees of the third party billing program in the 2013 Test Year as outlined in evidence at Exhibit D1, Tab 9, Schedule 1.

(i) Approval for the recovery of the 2013 DSM budget amount of $28.6 million. In EB-2011-0295, the Company's application for approval of a DSM budget for 2012 of $28.1 million, including an increase for inflation and a 10% increase In low income spending, was the subject of a complete settlement (although the Company has reserved the right to not spend the additional

10% on low income programs if a requested increase to the shareholder incentive is not approved). If the settlement is accepted by the Board there will be an increment to the 2013 revenue requirement of $0.5 million over the comparable amount for 2012 and this figure will not change materially in the event that the DSM Budget increase for 2012 is limited to inflation. Please refer to Exhibit D1, Tab 7, Schedule 1.

(j) Approval to revise the depreciation rates charged against Company assets as proposed by Gannett Fleming, Inc. in their depreciation study, filed in evidence at Exhibit D2, Tab 2, Schedule 1.

(k) Approval of the Company's proposed increase in the level of Deemed Common Equity, from 36% to 42% of rate base, as described in the Company's evidence at Exhibit E2, Tab 1, Schedule 2 and in evidence in support of the Company's request, submitted by the Concentric Energy Advisors, filed at Exhibit E2, Tab 2, Schedule 1.

(l) Approval of the Company's proposed deferral and variance (DA and VA) accounts for the 2013 Test Year as described in evidence at Exhibit D1, Tab 8, Schedule 1.

(m) Approval of the Company's proposed rate handbook filed in evidence at Exhibit H2, Tab 6, Schedule 1, effective January 1, 2013 for all rate classes.

# DRAFT ISSUES LIST

1. Implementation
   1.1. Does Enbridge Gas Distribution's ("EGD") application properly implement the 2013 revenue requirement associated with customer care and CIS costs that was approved in the EB-2011-0226 settlement agreement?
   1.2. Does EGD's application properly implement the Board's refined formula for the calculation of Return on Equity ("ROE") that was approved in EB-2009-0084?

2. Administration (Exhibit A)
   2.1. Does the evidence support the adoption of USGAAP for the establishment of rates in the 2013 Test Year?
   2.2. Does the evidence support the proposed change in accounting treatment related to the transition from the 'cash' to 'accrual' methodology for pension and other post employment benefits ("OPEBs") expense?

3. Rate Base and Capital Expenditures (Exhibit B)
   3.1. Does the evidence support the capital expenditure forecast?
   3.2. Does the evidence support the forecast level of rate base?

4. Operating Revenue Forecast (Exhibit C)
   4.1. Does the evidence support the revenue forecast?
   4.2. Does the evidence support the gas volume forecast?
   4.3. Does the evidence support degree day forecasts for each of the Company's delivery areas (EDA, CDA and Niagara)?
   4.4. Does the evidence support the average use forecast?

4.5. Does the evidence support the proposed level for Unaccounted For ("UAF") volume?

4.6. Does the evidence support the proposed changes to the Transactional Services ("TS") program and the resulting TS revenue forecast?

4.7. Does the evidence support the other revenue and late Payment Penalty ("LPP") forecast?

5. Operating Expense (Exhibit D)

5.1. Does the evidence support the gas cost forecast?

5.2. Does the evidence support the proposed changes to the Peak Gas Day Design Criteria ("PGDDC") and the proposed method of cost recovery?

5.3. Does the evidence support the Operations and Maintenance ("O&M") expense forecast?

5.4. Does the evidence support the implementation of the proposed changes to depreciation rates and the resultant level of depreciation expense?

5.5. Does the evidence support the level of municipal tax expense?

5.6. Doe the evidence support the income tax expense forecast?

5.7. Does the evidence support the proposed changes to the Open Bill Access ("OBA") program?

6. Cost of Capital (Exhibit E)

6.1. Does the evidence support the proposed changes to the capital structure, increasing the deemed equity level?

6.2. Does the evidence support the cost of capital forecast?

7. Revenue Requirement and the Determination of Sufficiency/(Deficiency) (Exhibit F)
   7.1. Does the evidence support the determination of revenue requirement and sufficiency/(deficiency)?

8. Cost Allocation and Rate Design (Exhibits G and H)
   8.1. Does the evidence support the allocation of cost and the design of the proposed rates and supporting rate schedules?
   8.2. Does the evidence support the approval of the Rate Handbook and the implementation of rates effective January 1, 2013?

9. Deferral and Variance Accounts
   9.1. Does the evidence support the proposed establishment and treatment of deferral and variance accounts?

10. Rate Implementation
   10.1. How should the Board implement rates, effective January 1, 2013, to allow EGD to recover its prospective revenue deficiency?

TAB IS A PLACE HOLDER FOR

FUTURE PROCEDURAL ORDERS, MOTIONS

AND CORRESPONDENCE

PARTIES ARE TO UPDATE THIS SECTION

# ACCOUNTING ORDERS

1. The current existing deferral and variance accounts ("DA's" and "VA's") that have been approved by the Board through the review and approval process of either regulatory proceedings or through separate accounting order requests were most recently approved in their entirety in the EB-2010-0146 Rate Order at Appendix D, pages 1 through 35.

2. Enbridge currently has a settlement agreement in the 2012 Test Year, docket number EB-2011-0277, for its requested DA's and VA's save and except three requested accounts. Still before the Board within its 2012 rate proceeding are (1) a 2012 Pension Funding Costs variance account, (2) a 2012 Cross Bore variance account and (3) a 2012 Transition Impact of Accounting Changes deferral account.

3. The Company's proposed 2013 deferral and variance accounts and treatments are found at Exhibit D1, Tab 8, Schedules 1 and 3.

# ACCOUNTING FOR RATE REGULATED OPERATIONS
# CURRENT AND FUTURE CHANGES

1. In this application Enbridge is requesting the Board's approval to utilize US Generally Accepted Accounting Principles ("USGAAP") as its approved framework for rate setting, regulatory accounting and regulatory reporting commencing January 1, 2013 in a manner appropriate for a rate regulated entity.

## Background

2. In February 2008, the Canadian Accounting Standards Board ("AcSB") determined that International Financial Reporting Standards ("IFRS") would become the new Canadian accounting standards for publicly accountable entities for periods beginning on or after January 1, 2011. In July 2010, the AcSB issued an Exposure Draft which would have allowed qualifying entities with rate regulated activities an optional two year deferral to adopt IFRS and would have permitted such entities to continue to apply the accounting standards ("CGAAP") in Part V of the Canadian Institute of Chartered Accountants ("CICA") Handbook during that period. Subsequently, in October 2010, the AcSB finalized its amendments to the CICA Handbook regarding the adoption of IFRS, stating the first-time adoption of IFRS for qualifying entities with rate regulated activities is mandatory effective January 1, 2012, which reduced the two year deferral period to one year. Enbridge is a qualifying entity for purposes of this deferral.

3. While the Enbridge IFRS conversion project was on track to meet the original conversion deadline, the Company elected to use in 2011 the one year deferral offered by the AcSB. This decision was made given the continuing uncertainty with respect to the basis of application of IFRS to the rate regulated operations of the

Company, which are a critical element of its business model and a key driver of financial performance. The International Accounting Standards Board ("IASB") originally issued an exposure draft on Rate Regulated Activities in 2009, but has since failed to finalize the accounting standard or provide definitive guidance on the direction of the project.

4. During the deferral period, the Company presented its financial statements in accordance with Part V of the CICA Handbook, and closely monitored developments of the IASB, and determined whether IFRS or USGAAP would provide the most useful and reliable presentation of its financial results for 2012 and future periods.

5. There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its commercial environment and performance measurement. The Company does not anticipate a rate regulated accounting standard to be finalized by the IASB in the near future. The Company believes USGAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated business.

Adoption of USGAAP

6. Enbridge has adopted USGAAP for external reporting purposes effective January 1, 2012. Enbridge will present comparative financial results restated in USGAAP for external reporting for the periods required by Canadian securities requirements. This will include at least the 2011 and 2010 fiscal years.

7. In EB-2008-0408, *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, "Appendix A, Issue 4, the Board summarizes its position as it relates to USGAAP. "The Board requires a utility that adopts USGAAP or an alternate accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to:

   - Demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using the standard;
   - Include a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable); and
   - Set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation."

8. The evidence filed with the Board includes:

   a. The eligibility of Enbridge under securities legislation to report financial information using USGAAP;
   b. The authorization of Enbridge to use USGAAP for financial reporting purposes;
   c. The explanation of the benefits of adopting USGAAP rather than Modified International Financial Reporting Standards ("MIFRS") for rate regulation purposes; and
   d. The potential regulatory disadvantages as a result of adopting USGAAP for rate regulation purposes.

Eligibility to report financial information using USGAAP

9. Enbridge is not a Securities Exchange Commission ("SEC") registrant in the US however, it does have publicly-held debt and is a reporting issuer in Ontario and must comply with all applicable provisions prescribed by the Ontario Securities Commission ("OSC").

10. Subsection 3.2 of National Instrument 52-107 requires financial statements to be prepared in accordance with CGAAP. As of January 1, 2011, the AcSB has adopted IFRS; however, Enbridge took advantage of subsection 5.4 of NI 52-107 to prepare CGAAP – Part V financial statements for the 2011 fiscal year only. This resulted in the continued application of rate regulated accounting for the 2011 fiscal year.

11. Enbridge Inc. filed an application on November 10, 2010 with the OSC and the Alberta Securities Commission, on behalf of Enbridge and other related reporting entities, to prepare financial statements for filing under USGAAP commencing January 1, 2012. Please see Appendix 1 for a copy of this application, which outlines the eligibility of Enbridge to report financial statements under USGAAP.

Authorization of Enbridge to use USGAAP for reporting purposes

12. On February 25, 2011, an exemption order was released which permitted Enbridge Inc. and its related reporting entities, including Enbridge, to report under USGAAP for financial reporting purposes. Please see Appendix 2 for a copy of the decision.

13. Pursuant to this order, Enbridge is permitted to file its financial statements in accordance with USGAAP for the financial year commencing January 1, 2012 up to up and including the financial year ending December 31, 2014.

Advantages of adopting USGAAP rather than MIFRS for rate regulation purposes

14. Adopting USGAAP would have a number of advantages for Enbridge, including the following:

a. Would ensure the continued alignment between Enbridge's financial reporting and its regulatory basis of accounting.
b. Would provide transparency and consistency between the accounting framework underlying external and Board reporting. Through this consistency, there is a clear link between the audited financial statements and regulatory decisions which would benefit the Board and all interested stakeholders. If there was a different basis of accounting, there would be additional Enbridge and Board costs associated with the complexities of dual reporting and the reconciliations between them including additional IT solutions. This continued reconciliation would become increasingly complex, costly and burdensome with every passing fiscal period.
c. Would better reflect the economic realities of the underlying business
d. Would better reflect the users of its financial statements preference to have the financial statements reflect the economic realities of the regulated operations.
e. Would ensure relative consistency in earnings and revenue requirements
f. Would preclude the need for establishing a principles based accounting justification (under IFRS) for each new regulatory event, thus preventing incremental administrative and audit costs.
g. Would provide consistency with industry approach, thus enhancing comparability.
h. Would not create a material shift from CGAAP.

15. One significant impact to Enbridge as a result of the adoption of MIFRS would be the increased costs which would no longer be able to be capitalized to capital assets. These costs would be recorded as current Operating costs and cause a significant increase in revenue requirement. The company does not plan on changing its capitalization policies as a result of converting to USGAAP.

16. Another significant impact under MIFRS would relate to the fact that the deferral accounts would likely not be treated as assets and liabilities. These accounts, even if approved by the OEB, would not qualify as asset and liabilities under MIFRS. Accordingly, there would be an immediate impact to earnings and a resulting volatility in earnings without a similar associated and immediate adjustment within rates.

17. Please see Appendix 3 for a summary of the estimated impact to Enbridge as a result of adopting USGAAP.

18. The Financial Accounting Standards Board issued FAS 71 in 1982 to permit the economic realities of rate regulation. These standards, subsequently re-codified as ASC 980, have proven to be a mature, reliable and an understandable set of accounting standards.

19. There appear to be many Canadian regulated utilities that are adopting USGAAP or considering adopting USGAAP. Union Gas is also converting to USGAAP which will mean that the two significant gas distribution utilities in Ontario are reporting in a consistent accounting methodology. Other examples of such companies include: Emera, Fortis BC, AltaGas, TransCanada Pipelines, Hydro One and Ontario Power

Generation. This would facilitate benchmarking with peer companies which will benefit Enbridge and its stakeholders.

20. Enbridge is of the view that harmonization of IFRS with USGAAP will not occur in the foreseeable future. By allowing Enbridge to file under USGAAP, there would be the consistency in reporting which would continue to permit benchmarking and other comparative analysis.

21. Overall, the Company is of the view that there will be less impact to the Company and to ratepayers as a result of adopting USGAAP vs MIFRS. Please see Appendix 3 for a summary of the estimated impact to Enbridge as a result of adopting MIFRS.

<u>Disadvantages of adopting USGAAP rather than MIFRS for rate regulation purposes</u>

22. Adoption of USGAAP may introduce an additional accounting framework from the Board's point of view for rate-making.

23. Many utilities in Ontario will likely not have the option of converting to USGAAP therefore there will be an inconsistent application of accounting principles between Enbridge and those entities. While there could be an impact in the amount of time spent by the Board in analyzing entities who have converted to USGAAP the impact of this is likely lessened however, as it appears that Union Gas will also be converting to USGAAP, which means the two significant natural gas distribution companies in Ontario will be filing under USGAAP. In addition, as indicated, some of the electric distribution companies in Ontario are considering filing in USGAAP.

24. There is also the potential for uncertainty with regards to longevity of the solution.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

25. As previously indicated, Enbridge has been granted OSC relief for the 2012 to 2014 fiscal periods. While the Company is confident that it will continue to utilize USGAAP after 2014, there is no resolution that has been decided upon. Enbridge views the limited period exemption provided by the OSC being reflective of the uncertainty with regards to the treatment of rate-regulated operations under IFRS, recognizing that the USGAAP guidance on this front is better reflective of the economic outcomes of the business. Enbridge expects to pursue a further exemption from the OSC at the end of the exemption period, unless IFRS guidance on this front, by that time, becomes largely aligned with that of USGAAP. As an alternative, Enbridge also will have the ability to register with the SEC in the US, so as to secure continued use of USGAAP for financial reporting purposes.

Post-employment benefits

26. In its 2012 rates application EB-2011-0277, Enbridge requested approval to establish a 2012 Transition Impact of Accounting Changes Deferral Account ("TIACDA"). The purpose of this account is to recognize and record the financial impacts that will occur in 2012 in relation to Enbridge's required transition away from current CGAAP.

27. Enbridge's evidence at Exhibit A2, Tab 3, Schedule 1 explains the requested recovery of the amount in relation to the required Other Post-employment benefits ("OPEB") accounting change and impact which occur as of 2012 as a result of transitioning off CGAAP and the request to adopt the accrual method of accounting for OPEB. The same impact and request would have occurred if Enbridge had chosen to adopt IFRS. As explained in that evidence, Enbridge is seeking recovery of the amount to be recorded in the TIACDA, $90 million, over a fifteen year period commencing in 2013.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Enbridge Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, AB T2P 3L8
Canada
www.enbridge.com

Debra J. Poon
Senior Legal Counsel

Tel: 403 767-3642
Fax: 403 231-7380
debra.poon@enbridge.com

November 10, 2010

**VIA COURIER AND EMAIL**

Alberta Securities Commission
4th Floor, 300 – 5th Avenue SW
Calgary, AB T2P 3C4

**Attention: Director, Corporate Finance**
Email: legalapplications@seccom.ab.ca

Ontario Securities Commission
Suite 1903, Box 55
20 Queen Street West
Toronto, ON M5H 3S8

**Attention: The Secretary to the Commission**
Email: applications@osc.gov.on.ca

Dear Sirs/Mesdames:

**Re: Application Pursuant to Section 9.1 of National Instrument 52-107 *Acceptable Accounting Principles, Auditing Standards and Reporting Currency* to Permit the Filing of US GAAP Financial Statements for Affiliates of an SEC Issuer**

Application is hereby being made by Enbridge Inc. ("**EI**"), Enbridge Gas Distribution Inc. ("**EGD**"), Enbridge Pipelines Inc. ("**EPI**"), Enbridge Income Fund ("**EIF**") and Enbridge Income Fund Holdings Inc. ("**EIFH**") to the securities regulator or regulatory authority (as applicable) in the Provinces of Alberta, British Columbia, Saskatchewan, Manitoba, Quebec, Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland and Labrador (the "**Passport Jurisdictions**") and to the Ontario Securities Commission ("**OSC**") for exemptive relief pursuant to section 9.1 of National Instrument 52-107 *Acceptable Accounting Principles, Auditing Standards and Reporting Currency* ("**NI 52-107**") and section 5.1 of National Instrument 52-107 *Acceptable Accounting Principles and Auditing Standards* ("**New NI 52-107**") from the requirements of sections 3.2 of New NI 52-107 to permit the preparation and filing by EGD, EPI, EIF and EIFH (collectively, the "**Affiliates**") of US GAAP financial statements for financial years commencing on or after January 1, 2012. EI and the Affiliates are collectively referred to as the "**Filers**".

This is a dual application made to the Alberta Securities Commission ("**ASC**") as the principal regulator for the Passport Jurisdictions and to the OSC. The OSC is the principal

regulator for EGD as its head office is located in Ontario. However the Filers request that the ASC be designated as the principal regulator for this application as it is the principal regulator of all of the other Filers (including EI, of which EGD is an indirect wholly-owned subsididary), which have their head office in Alberta. Please consider this a written request pursuant to section 3.7 of National Policy 11-203 *Process for Exemptive Relief Applications in Multiple Jurisdictions* (**"NI 11-203"**) for a change in principal regulator in respect of EGD for this application only.

Notice that section 4.7(1) of MI 11-102 *Passport System* is being relied upon for the Passport Jurisdictions is hereby given to the ASC as principal regulator. The exemption for which relief is sought is from the requirements of sections 3.2 of New NI 52-107 (expected to come into force on January 1, 2011) in respect of the financial statements of the Affiliates.

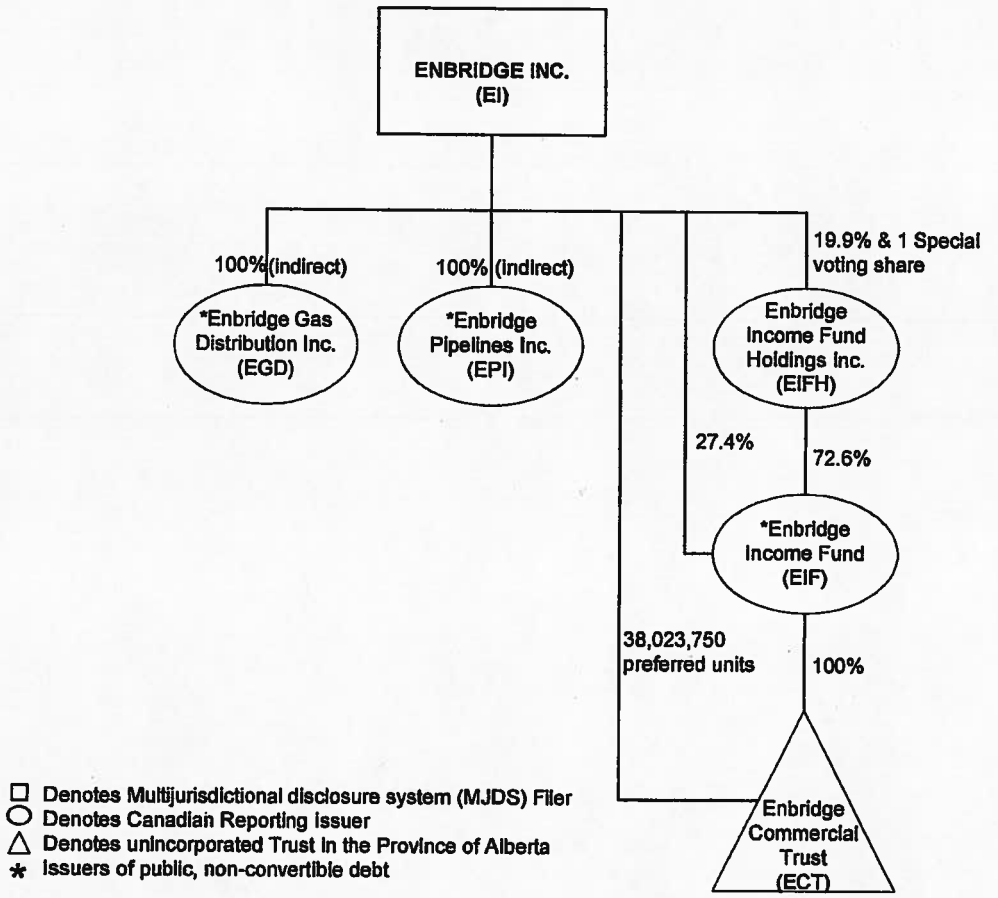
The Filers are also seeking confidentiality of this application, the supporting materials and the decision pursuant to section 5.4 of NI 11-203. Confidentiality is being sought as the Filers have not yet publicly announced their intention to implement US GAAP pending the outcome of this application. Accordingly, we request confidentiality be extended until the earlier of (a) the date the Filers announce to the public that they will be transitioning to US GAAP; (b) the date the Filers advise the principal regulator that there is no longer any need for the application and this decision to remain confidential; and (c) 90 days following the date of the decision. We submit that maintaining the confidentiality requested will not be prejudicial to the public interest.

***Facts***

EI and all of the Affiliates with the exception of EIFH are reporting issuers in the Passport Jurisdictions and Ontario. EGD and EPI are indirect wholly-owned subsidiaries of EI and have public holders of non-convertible debt securities. EIFH will become a reporting issuer following completion of an arrangement (**"Arrangement"**) involving EIF and EIF unitholders (**"Unitholders"**), as described in the EIF information circular dated March 31, 2010 (filed on SEDAR on April 7, 2010). The Arrangement is being effected primarily due to changes to Canadian federal income tax legislation relating to specified investment flow-through trusts and is expected to be completed on or about December 15, 2010. The activities of EIFH will be restricted to investment in EIF following completion of the Arrangement. EI and EIFH will be the only holders of EIF units and the Unitholders and EI will be the shareholders of EIFH. The Toronto Stock Exchange has conditionally approved the listing of the EIFH shares following completion of the Arrangement.

Following the Arrangement, EI will own 27.4% of the EIF units and 19.9% of the EIFH shares. Together with these interests and its preferred unit investment in Enbridge Commercial Trust (a wholly-owned subsidiary of EIF), EI holds a combined direct and indirect economic interest in EIF of 72%. EIF will continue to be a reporting issuer following completion of the Arrangement as it will still have public holders of non-convertible debt securities.

The summarized organizational structure depicting EI's direct and indirect ownership of the Affiliates following the effective date of the Arrangement is set out below. Note that for ease of reference, we have omitted wholly-owned direct and indirect non-reporting issuer subsidiaries of EI that are between EI and EGD and EI and EPI.




Each of EI and the Affiliates are or will be a "qualifying entity" and intend to rely on the optional one-year deferral from International Financial Reporting Standards ("**IFRS**") specified in section 5.4 of the New NI 52-107 to prepare and file Canadian GAAP (pre-changeover) financial statements for the financial year commencing January 1, 2011 and ending December 31, 2011.

EI is required to file reports with the United States Securities and Exchange Commission ("**SEC**") under section 15(d) of the *United States Securities Exchange Act of 1934* (the "**1934 Act**") and the common shares of EI are also listed and posted for trading on the New York Stock Exchange.

The Affiliates are not currently "SEC Issuers" and therefore do not file reports with the SEC. Further facts relating to the Filers are set forth in the enclosed draft Decision

***Submissions***

EI is an "SEC Issuer" as defined in New NI 52-107 and accordingly, may rely on sections 3.7 and 3.8 of New NI 52-107 to prepare and file US GAAP financial statements for the financial years commencing on or after January 1, 2012.

The consolidated financial statements of EI include the accounts of the Affiliates, which must be prepared using the same basis of accounting as EI. However, as the Affiliates are not SEC Issuers, section 3.7 of New NI 52-107 is not available to enable the Affiliates to file US GAAP financial statements to comply with the continuous disclosure obligations under Canadian securities laws (the "**Legislation**").

While the New NI 52-107 is not yet in effect, the conversion to US GAAP is a significant and complex undertaking which will require considerable time to complete. EI and the Affiliates are therefore seeking exemptive relief in advance of New NI 52-107 taking effect. We respectfully submit that the Affiliates should not be required to prepare two sets of financial statements using different accounting principles and should be permitted to prepare and file US GAAP financial statements to comply with the Legislation for the reasons set forth below.

1. There is continuing uncertainty with respect to the application of IFRS to the rate regulated operations of the Filers, which are pervasive and central to its business model and a key driver of financial performance. Management of the Filers believe that US GAAP articulates more guidance than IFRS and faithfully represents the economic realities of its regulated businesses; providing a well recognized, accepted and comprehensive basis of accounting and financial reporting. As NI 52-107 already permits SEC Issuers to file US GAAP financial statements in satisfaction of Canadian reporting requirements, the Canadian investor base understands and can interpret US GAAP.

2. There is likely to be confusion if the financial statements of EI and the Affiliates filed on SEDAR and made available to public stakeholders and Industry Regulators are not on a consistent basis as the differences between IFRS and US GAAP are pervasive. For example, the Affiliates would be required to write-off regulatory assets and liabilities in the absence of any specific guidance under IFRS, whereas US GAAP permits the recognition of such assets and liabilities. Publishing the financial results of the Filers in the public domain under different accounting principles detracts from the objectives of providing relevant and transparent financial reporting and does not serve the best interests of stakeholders.

3. Significantly greater resources and expense will be required on a continuous basis to prepare, review and audit two different sets of financial statements for each Affiliate in addition to supplemental financial information required by industry

regulators ("**Industry Regulators**"), including without limitation, the National Energy Board and the Ontario Energy Board. The differences between IFRS and US GAAP are extensive and maintaining two sets of financial statements would drastically increase the cost and complexity of the Affiliates' financial statement reporting process with no perceived benefit to users of those financial statements.

4. Rate regulated accounting is well established in Canada and the US and EI already complies with ASC 980 Regulated Operations, the US GAAP standard on rate regulated accounting. As EI has reconciled its consolidated financial statements to US GAAP for many years, users of its financial statements will have a consistent basis of reference when analyzing EI on a historical basis.

5. EI, through its subsidiaries and affiliates (including the Affiliates), has significant assets and operations in the US, the primary market for securities of EI outside of Canada is the US and US GAAP would enhance comparability with many industry peers.

6. EI's related US public issuers, Enbridge Energy Management, L.L.C. and Enbridge Energy Partners, L.P. are also registered with the SEC and currently prepare and file US GAAP financial statements pursuant to the 1934 Act and under both US GAAP and IFRS will be required to consolidate its financial statements into EPI's which in turn will consolidate its financial statements into EI's.

7. Although it may be possible for the Affiliates to be eligible to file US GAAP financial statements by becoming "SEC Issuers", we respectfully submit that the Affiliates should not be required to incur the significant expense involved in registering and making filings with the SEC, as well as assuming additional regulatory and PCAOB audit obligations, merely to comply with the Legislation.

***Authorities***

This application may be considered "novel" as New NI 52-107 was only recently published and is not expected to come into force until January 1, 2011. However, there are many decisions whereby the ASC, OSC and other Canadian securities regulatory authorities have granted relief from the requirements of NI 52-107 and in particular, the requirement to file the form of financial statements mandated by NI 52-107, including:

1. *In the Matter of Nortel Networks Limited*, OSC April 15, 2010;

2. *In the Matter of Brookfield Asset Management Inc.*, OSC August 25, 2008;

3. *In the Matter of Potash Corporation of Saskatchewan Inc.*, OSC August 6, 2010;

4. *In the Matter of IESI-BFC Ltd.*, OSC September 3, 2010;

5. *In the Matter of SXC Health Solutions Corp.*, OSC July 14, 2008;

6. *In the Matter of DaimlerChrysler Canada Finance Inc. and DaimlerChrysler AG,* OSC June 30, 2005; and

7. *In the Matter of Total Capital S.A. and Total Capital Canada Ltd.*, OSC June 16, 2010.

In *Nortel*, the applicant was a reporting issuer and a wholly-owned direct subsidiary of a reporting issuer that was an SEC Issuer. Similar to the Affiliates, the applicant had outstanding debt securities held by the public which were not listed on any stock exchange. Both the applicant and parent had prepared and filed US GAAP financial statements. Relief was granted to permit the applicant to continue to prepare and file US GAAP financial statements even though it ceased to be an "SEC issuer" and was therefore not eligible to continue to use the exemption in NI 52-107 to permit it to prepare and file US GAAP financial statements.

In *Brookfield*, the OSC granted relief to permit the early filing (for financial periods beginning on or after January 1, 2009) of IFRS-IASB financial statements by a reporting issuer which was also an SEC Issuer that had subsidiaries which were both Canadian reporting issuers and SEC registrants "subject to a diverse set of financial reporting requirements". The applicant submitted that the adoption of IFRS-IASB would be in the its best interest as it would result in additional information that would enhance shareholders' understanding of its results of operations and financial position and reduce the number of bases of accounting prepared by the applicant. The headnote to the decision stated that the applicant wished to "reduce the complexity of its financial statement preparation process". We respectfully submit that the rationale in *Brookfield* applies to this application. It is the Filers' opinion that US GAAP currently presently offers a better alternative for rate regulated entities than IFRS in enhancing the readers' understanding of the Filers' operations and financial position.

The rationale in *Brookfield* has been accepted in more recent decisions, such as *Potash* in which the applicant represented that the adoption of IFRS-IASB would be in its best interests and that of users of its financial statements as it would simplify its financial statements by possibly eliminating the requirement to reconcile to US GAAP, and the use of a single set of accounting principles throughout the applicant's subsidiaries and significant investees would reduce the cost and complexity of its financial statement preparation process.

The applicant in *IESI-BFC* was a reporting issuer which had adopted US GAAP. Relief was granted from a number of requirements in NI 52-107 in respect of financial disclosure relating to the acquisition of an entity which did not use Canadian GAAP as the basis of its accounting and financial reporting and as a result of the acquisition, became part of the applicant's consolidated business. It was stated that the applicant had adopted US GAAP as the comprehensive basis of accounting and financial reporting and as such a Canadian GAAP reconciliation was not necessary in order for investors to have a consistent basis of accounting for the applicant's financial disclosure and financial statements. Similar relief

was granted in *SXC Health*. Both of these decisions support our submission that there should be one consistent basis of accounting for businesses consolidated into a parent entity.

The Legislation provides financial reporting exemptions, including for the filing of financial statements, to reporting issuers that are wholly-owned subsidiaries and/or issuers of credit rated debt securities only. It also recognizes and accepts financial statements prepared in accordance with US GAAP in certain circumstances, such as in Part 13 of National Instrument 51-102 *Continuous Disclosure Obligations* (**"NI 51-102"**). For example, section 13.4 of NI 51-102 provides relief, including from the obligation to file financial statements, to a wholly-owned credit support reporting issuer if certain conditions are met, including that only credit rated debt securities are issued. If the parent credit supporter is an "SEC Issuer" or not a reporting issuer in Canada, it can instead file the parent's financial statements and documents required to be filed by the SEC or under U.S. laws. A number of decisions have been issued by the securities regulatory authorities granting relief in circumstances where the applicants did not technically comply with the requirements of section 13.4 of NI 51-102. In both *Daimler* and *Total*, relief was granted as the parent was not organized or incorporated under U.S. laws (but was an SEC filer) and as the debt securities did not technically fall within the definition of "designated credit support securities". Further, relief was granted in *Total* despite its subsidiary not being wholly-owned by Total or Total's affiliates.

Although the present circumstances do not involve a credit support or guarantee by EI of the securities of its Affiliates, we respectfully submit that similar policy considerations apply. The exemption is based on the fact that the parent has sufficient financial strength such that its guarantee enables the securities of its subsidiary(ies) to obtain a credit rating. The rationale for the exemption should turn on the credit rating and not on whether a parental guarantee is provided. If US GAAP financial statements can be filed by a reporting issuer offering credit approved debt in Canada that has been guaranteed by a parent subject to SEC filing obligations, the filing of US GAAP statements should also be available for a reporting issuer offering credit approved debt (whose parent is also subject to SEC filing obligations) regardless of whether a parental guarantee is required to obtain a credit rating. Investors are only concerned with receiving the financial statements of the entity which has the obligation to repay the debt, which does not drive the presentation of the financial statements. Therefore, the basis of the exemption must be that the subsidiary reporting issuer or the SEC parent filer should not be required to incur the expense of preparing an additional set of financial statements (under Canadian GAAP) to comply with the Legislation and that US GAAP financial statements are considered an acceptable alternative.

Given that Canadian securities regulators have granted broad based relief to permit a reporting issuer that is a subsidiary of a foreign issuer to file its parent's US GAAP financial statements, we suggest that it is not prejudicial to the public interest to permit a subsidiary of a Canadian SEC issuer to file its **own** financial statements prepared in accordance with US GAAP.

The *Total* decision is also a precedent for the confidentiality sought for this application and the decision.

Please find enclosed:

1. draft Decision;

2. Verification Statement;

3. to the ASC only, a cheque payable to the ASC in the sum of $750; and

4. to the OSC only, a cheque payable to the OSC in the sum of $3,250.

Please do not hesitate to contact the writer if you have any questions or require anything further. Please note that as significant lead time will be required to identify and implement the procedures necessary to effect a conversion of the Filers' financial statements and financial reporting, we would very much appreciate your early response.

Yours truly,

Debra J. Poon
Senior Legal Counsel

Encls.

## VERIFICATION STATEMENT

We authorize the making and filing of the attached application by Debra J. Poon, Senior Legal Counsel, Enbridge Inc. and confirm the truth of the facts contained therein.

DATED at Calgary, Alberta this 10th day of November, 2010.

**ENBRIDGE INC.**

Per: _____
J. Richard Bird, Executive Vice President,
Chief Financial Officer & Corporate Development

**ENBRIDGE MANAGEMENT SERVICES INC.**
**as Administrator of ENBRIDGE INCOME FUND**

Per: _____
Colin K. Gruending, Chief Financial Officer

**ENBRIDGE INCOME FUND HOLDINGS INC.**

Per: _____
Wanda Opheim, Director

DATED at Edmonton, Alberta this 10th day of November, 2010.

**ENBRIDGE PIPELINES INC.**

Per: _____
William G. Ross, Vice President, Finance

DATED at Toronto, Ontario this 10th day of November, 2010.

**ENBRIDGE GAS DISTRIBUTION INC.**

Per: _____
Narin Kishinchandani, Vice President, Finance

**Citation: Enbridge Inc., Re, 2011 ABASC 106** **Date: 20110225**

In the Matter of
the Securities Legislation of
Alberta and Ontario (the **Jurisdictions**)

and

In the Matter of
the Process for Exemptive Relief Applications in Multiple Jurisdictions

and

In the Matter of

Enbridge Inc., Enbridge Gas Distribution Inc.
and Enbridge Pipelines Inc. (the **Filers**)

Decision

**Background**

The securities regulatory authority or regulator in each of the Jurisdictions (the **Decision Maker**) has received an application from the Filers for a decision under the securities legislation of the Jurisdictions (the **Legislation**) exempting Enbridge Gas Distribution Inc. (**EGD**) and Enbridge Pipelines Inc. (**EPI**), (collectively, the **Affiliates**) from the requirements in subsection 3.2 of National Instrument 52-107 *Acceptable Accounting Principles and Auditing Standards* (**NI 52-107**) that financial statements be prepared in accordance with Canadian GAAP - Part I (the **Exemption Sought**) to permit the Affiliates to prepare their financial statements in accordance with United States generally accepted accounting principles (**US GAAP**).

Under the Process for Exemptive Relief Applications in Multiple Jurisdictions (for a dual application):

(a) the Alberta Securities Commission is the principal regulator for this application;

(b) the Filers have provided notice that subsection 4.7(1) of Multilateral Instrument 11-102 *Passport System* (**MI 11-102**) is intended to be relied upon in British Columbia, Saskatchewan, Manitoba, Québec, Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland and Labrador (the **Passport Jurisdictions**); and

(c) the decision is the decision of the principal regulator and evidences the decision of the securities regulatory authority or regulator in Ontario.

**Interpretation**
Terms defined in National Instrument 14-101 *Definitions,* MI 11-102 and NI 52-107 have the same meaning if used in this decision, unless otherwise defined.

**Representations**
This decision is based on the following facts represented by the Filers:

*Enbridge Inc.*

1. Enbridge Inc. (**EI**) was incorporated under the *Companies Act* (NWT) on April 13, 1970 and continued under the *Business Corporations Act* (Canada) on December 15, 1987. The head office of EI is in Calgary, Alberta.

2. EI is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions and, to its knowledge, is not in default of securities legislation in any jurisdiction in Canada.

3. The securities of EI are listed on the Toronto Stock Exchange (**TSX**) and the New York Stock Exchange (**NYSE**).

4. EI is an "SEC issuer" as that term is defined in NI 52-107 and can rely on subsection 3.7 of NI 52-107 to prepare and file with, or deliver to, a securities regulatory authority or regulator US GAAP financial statements.

*Enbridge Pipelines Inc.*

5. EPI was incorporated by Special Act of Canada on April 30, 1949 and continued under the *Business Corporations Act* (Canada) on June 2, 1980. The head office of EPI is in Calgary, Alberta.

6. EPI is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions and, to its knowledge, is not in default of securities legislation in any jurisdiction in Canada.

7. EPI does not have any "exchange-traded securities" as that term is defined in National Instrument 21-101 *Marketplace Operation* (**NI 21-101**).

8. EPI is a wholly-owned indirect subsidiary of EI and has issued and outstanding the following publicly-held debt (as at January 31, 2011) that is not convertible into equity securities of any issuer:

   $200,000,000 Series K Debentures at 8.20%
   $2,424,600,000 Medium Term Notes at rates ranging from 2.93% to 6.62%
   $25,500,000 in Commercial Paper

9. EPI is a rate-regulated entity whose business includes, through a wholly-owned subsidiary, 100% voting control of Enbridge Energy Management, L.L.C. (**EEM**), which holds an indirect 25.5% ownership interest in Enbridge Energy Partners, L.L.P. (**EEP**).

10. EEM and EEP are not reporting issuers or equivalent in any jurisdiction of Canada, but are registrants with the SEC and their securities are listed on the NYSE.

11. EEM and EEP prepare and file US GAAP financial statements with the SEC pursuant to the 1934 Act and, pursuant to US GAAP and International Financial Reporting Standards (**IFRS**), such financial statements must be consolidated into the financial statements of EPI, which will in turn be consolidated into the financial statements of EI.

12. EPI is not an "SEC issuer" as that term is defined in NI 52-107.

*Enbridge Gas Distribution Inc.*

13. EGD was incorporated by Special Act of Canada in 1848. EGD was continued under the *Corporations Act, 1953* (Ontario) and is now subject to the *Business Corporations Act* (Ontario). The head office of EGD is in Toronto, Ontario.

14. EGD is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions, and to its knowledge, is not in default of securities legislation in any jurisdiction of Canada.

15. EGD does not have any "exchange-traded securities" as that term is defined in NI 21-101.

16. EGD is a wholly-owned indirect subsidiary of EI and has outstanding the following publicly-held debt (as at January 31, 2011) that is not convertible into equity securities of any issuer:

    $235,000,000 Debentures at rates of 9.85% and 10.80%; and
    $2,195,000,000 Medium Term Notes at rates ranging from 4.045% to 8.85%

17. EGD is a rate-regulated natural gas distribution utility.

18. EGD is not an "SEC Issuer" as that term is defined in NI 52-107.

*General*

19. Each of the Filers are rate-regulated entities and, accordingly, may rely on subsection 5.4 of NI 52-107 to prepare and file Canadian GAAP - Part V financial statements for the financial year commencing January 1, 2011 and ending December 31, 2011.

20. It was anticipated that the International Accounting Standards Board's (**IASB**) exposure draft would have provided direction regarding rate-regulated accounting under IFRS effective prior to the January 1, 2011 transition date to IFRS to assist rate-regulated issuers with their IFRS transition. However, due to divergent views on rate-regulated accounting at the IASB, a rate-regulated accounting standard has not been finalized. There continues to be significant uncertainty as to when, and if, rate-regulated accounting under IFRS will be clarified.

21. Rate-regulated accounting is well established in the United States and EI already complies with ASC 980 *Regulated Operations*, the US GAAP standard on rate regulated accounting. EI has reconciled its financial statements to US GAAP for many years.

22. NI 52-107 permits SEC issuers to file US GAAP financial statements in satisfaction of requirements under the securities legislation of the Jurisdictions and the Passport Jurisdictions and does not require any reconciliation of US GAAP financial statements to Canadian GAAP.

23. As an SEC Issuer, EI may rely on subsection 3.7 of NI 52-107 to prepare and file US GAAP financial statements and intends to do so for the financial years commencing on or after January 1, 2012.

24. The financial statements of the Affiliates are consolidated into the financial statements of EI. As the Affiliates are not SEC issuers, they cannot rely on subsection 3.7 of NI 52-107 to file US GAAP financial statements.

25. The Affiliates will certify their interim and annual US GAAP financial statements by filing the appropriate certificates in accordance with National Instrument 52-109 *Certification of Disclosure*.

**Decision**

Each of the Decision Makers is satisfied that the decision meets the test set out in the Legislation for the Decision Maker to make the decision.

The decision of the Decision Makers under the Legislation is that the Exemption Sought is granted for the financial years commencing January 1, 2012 until the financial year ending December 31, 2014 in respect of each Affiliate provided that:

(a) EI, directly or indirectly, remains the holder of all of the equity securities in respect of the Affiliate;

(b) the Affiliate does not issue any "exchange traded securities" as that term is defined in NI 21-101, and any securities convertible into equity securities of the Affiliate are held directly or indirectly by EI; and

(c) the financial statements of the Affiliate continue to be consolidated into the financial statements of EI.

Cheryl McGillivray, CA
Manager, Corporate Finance

Appendix 3
**Enbridge Gas Distribution Inc.** DRAFT
**Canadian GAAP to US GAAP Reconciliation - Balance Sheet**
**December 31, 2010**

| | | US GAAP Adjustments | | | |
|---|---|---|---|---|---|
| | **Reported C-GAAP** | **Push Down Accounting (1)** | **Pension/OPEB (Net of Tax)** | **Deferred Financing Costs (2)** | **Reported US GAAP** |
| *(millions of Canadian dollars)* | | | | | |
| **Assets** | | | | | |
| Current assets | | | | | |
| Accounts receivable and other | 802 | | | | 802 |
| Gas inventories | 400 | | | | 400 |
| | 1,202 | - | - | - | 1,202 |
| Property, plant and equipment, net | 4,458 | 646 | | | 5,104 |
| Investment in affiliate company | 825 | | | | 825 |
| Deferred amounts and other assets | 487 | (4) | (229) | 20 | 274 |
| Intangible assets | 167 | | | | 167 |
| | 7,139 | 642 | (229) | 20 | 7,572 |
| **Liabilities and shareholders' equity** | | | | | |
| Current liabilities | | | | | |
| Bank overdtaft | 18 | | | | 18 |
| Short-term borrowings | 332 | | | | 332 |
| Accounts payable and other | 836 | | 3 | | 839 |
| Current maturities of long-term debt | 150 | | | | 150 |
| Deferred income taxes | 5 | | | | 5 |
| | 1,341 | - | 3 | - | 1,344 |
| Long-term debt | 2,267 | | | 20 | 2,287 |
| Other long-term liabilities | 1,058 | | (153) | | 905 |
| Deferred income taxes | 171 | 162 | (20) | | 313 |
| Loans from affiliate company | 375 | | | | 375 |
| | 5,212 | 162 | (170) | 20 | 5,224 |
| **Shareholders' equity** | | | | | |
| Share capital | | | | | |
| Preferred shares | 100 | | | | 100 |
| Common shares | 1,071 | | | | 1,071 |
| Additional paid-in capital | 202 | 929 | | | 1,131 |
| Retained earnings | 572 | (449) | (62) | | 61 |
| Accumulated other comprehensive loss | (18) | | 3 | | (15) |
| Total equity | 1,927 | 480 | (59) | - | 2,348 |
| Total Liabilities and Shareholder's Equity | 7,139 | 642 | (229) | 20 | 7,572 |

**(1)** The push-down accounting adjustments are not part of the regulated opeartions of EGD and therefore have no impact on regulated earnings.

**(2)** This entry is a balance sheet reclass and therefore has no impact on net assets or earnings.

**Enbridge Gas Distribution Inc.** DRAFT
**Canadian GAAP to US GAAP Reconciliation - Income Statement**
**Year Ended December 31, 2010**

| | Reported C-GAAP | US GAAP Adjustments: Push Down Accounting (1) | US GAAP Adjustments: Pension/OPEB (Net of Tax) | US GAAP Adjustments: Regulatory Deferral (2) | Reported US GAAP |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Gas commodity and distribution revenue | 1,977 | | | (201) | 1,776 |
| Transportation of gas for customers | 390 | | | 5 | 395 |
| | 2,367 | - | - | (196) | 2,171 |
| Gas commodity and distribution costs, excluding depreciation | (1,372) | | | 206 | (1,166) |
| Gas distribution margin | 995 | - | - | 10 | 1,005 |
| Other revenue | 108 | | | | 108 |
| | 1,103 | - | - | 10 | 1,113 |
| Expenses | | | | | |
| Operating and administrative | 393 | | 3 | 10 | 406 |
| Depreciation and amortization | 270 | 22 | | | 292 |
| Municipal and other taxes | 44 | | | | 44 |
| Earnings sharing | 19 | | | | 19 |
| | 726 | 22 | 3 | 10 | 761 |
| | 377 | (22) | (3) | - | 352 |
| Affiliate financing income | 63 | | | | 63 |
| Interest expense | (186) | | | | (186) |
| | 254 | (22) | (3) | - | 229 |
| Income taxes | | | | | |
| Current | (59) | | | | (59) |
| Deferred | (2) | 7 | 1 | | 6 |
| | (61) | 7 | 1 | - | (53) |
| Earnings | 193 | (15) | (2) | - | 176 |
| Preferred share dividends | (2) | | | | (2) |
| Earnings attributable to the common shareholder | 191 | (15) | (2) | - | 174 |

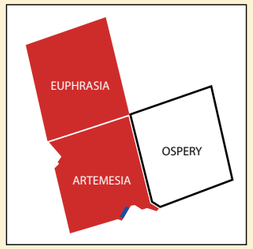
**(1)** The push-down accounting adjustments are not part of the regulated opeartions of EGD and therefore have no impact on regulated earnings.

**(2)** These adjustments have no net impact on earnings.

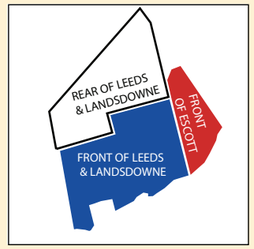
# NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

1. Enbridge Gas Distribution Inc. is in compliance with the Uniform System of Accounts.

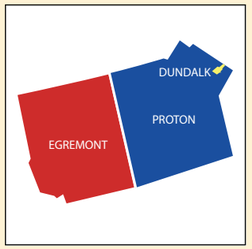
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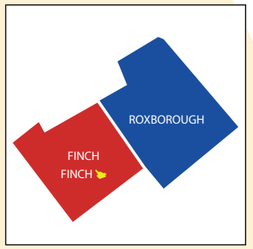

**GREY HIGHLANDS**



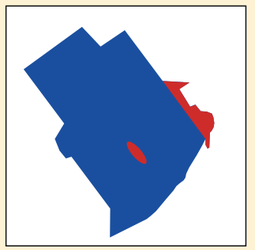

**LEEDS AND THE THOUSAND ISLANDS**




**SOUTHGATE**



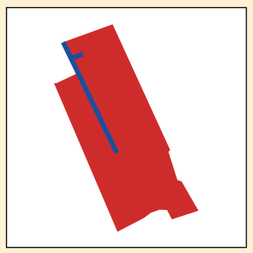

**NORTH STORMONT**



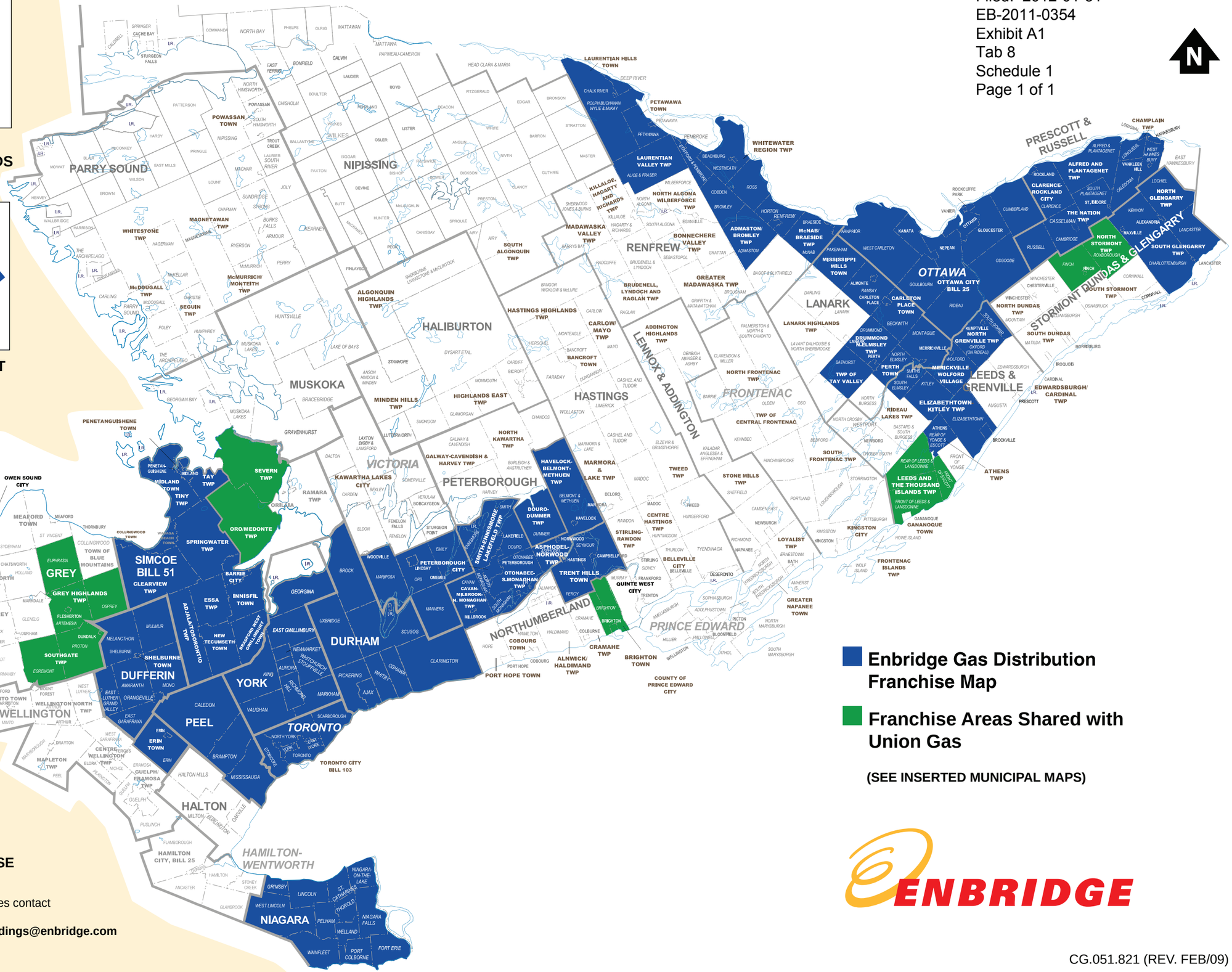
**ORO-MEDONTE**



**SEVERN**



**BRIGHTON**




For any franchise inquiries contact
Regulatory Affairs at:
**EGDRegulatoryProceedings@enbridge.com**
**(416) 495-5499**

**Enbridge Gas Distribution Franchise Map**

**Franchise Areas Shared with Union Gas**

**(SEE INSERTED MUNICIPAL MAPS)**

ENBRIDGE

CG.051.821 (REV. FEB/09)

# LIST OF AFFILIATE TRANSACTIONS

1. The following is a list of affiliate transactions in respect of services obtained by Enbridge Gas Distribution Inc. and recoveries/sales by Enbridge Gas Distribution:

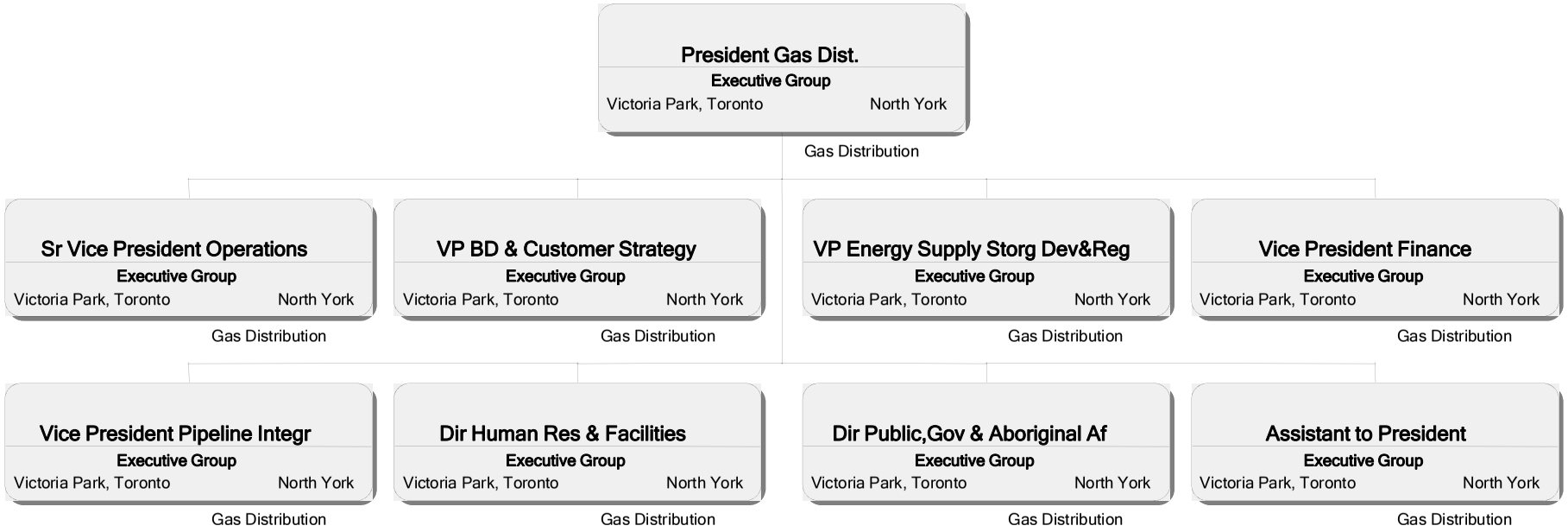
Summary of Affiliate Purchases
(in millions of dollars)

| Item No. | | Col. 1 Budget 2013 | Col. 2 Estimate 2012 | Col. 3 Historic 2011 |
|---|---|---|---|---|
| 1 | Enbridge Inc. | 45.4 | 44.9 | 39.4 |
| 2 | 2193914 Canada Limited | 0.8 | 0.7 | 0.7 |
| 3 | Enbridge Pipelines Inc. | 1.9 | 1.9 | 2.1 |
| 4 | Enbridge Operations Services | 1.9 | 1.9 | 1.9 |
| 5 | Vector Pipelines | 24.7 | 25.3 | 24.0 |
| 6 | Alliance Pipelines | 42.5 | 42.5 | 42.4 |
| | | 117.2 | 117.2 | 110.5 |

Summary of Affiliate Recoveries/Sales
(in millions of dollars)

| Item No. | | Budget 2013 | Estimate 2012 | Historic 2011 |
|---|---|---|---|---|
| 1 | Enbridge Inc. | 1.5 | 1.6 | 1.9 |
| 2 | Niagara Gas Transmission Ltd. | 0.4 | 0.4 | 0.3 |
| 3 | 2193914 Canada Limited | 0.1 | 0.2 | 0.3 |
| 4 | St Lawrence Gas Co. Ltd. | 0.2 | 0.2 | 0.2 |
| 5 | Gazifere Inc. | 29.4 | 29.2 | 28.2 |
| 6 | Enbridge Energy Distribution Inc. | 0.4 | 0.3 | 0.4 |
| 7 | Enbridge Gas New Brunswick LP | 1.0 | 1.0 | 0.9 |
| 8 | Enbridge Gas New Brunswick Inc. | 0.3 | 0.3 | 0.2 |
| | | 33.3 | 33.2 | 32.4 |

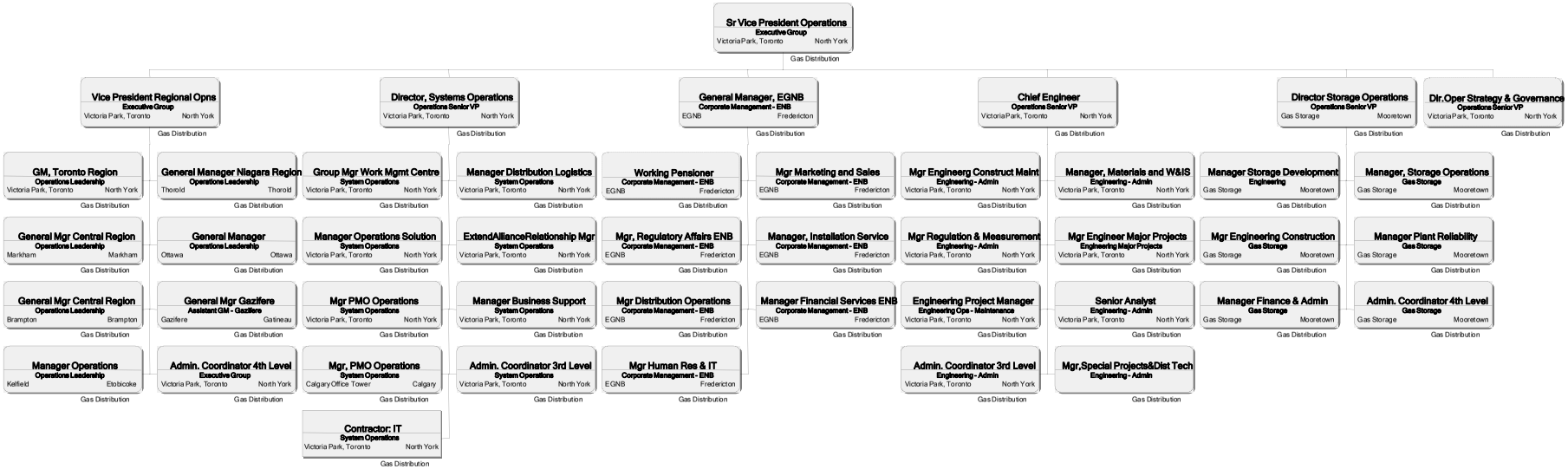
Witnesses: J. Jozsa
B. Yuzwa




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Employee
Temp Employee
Contractor

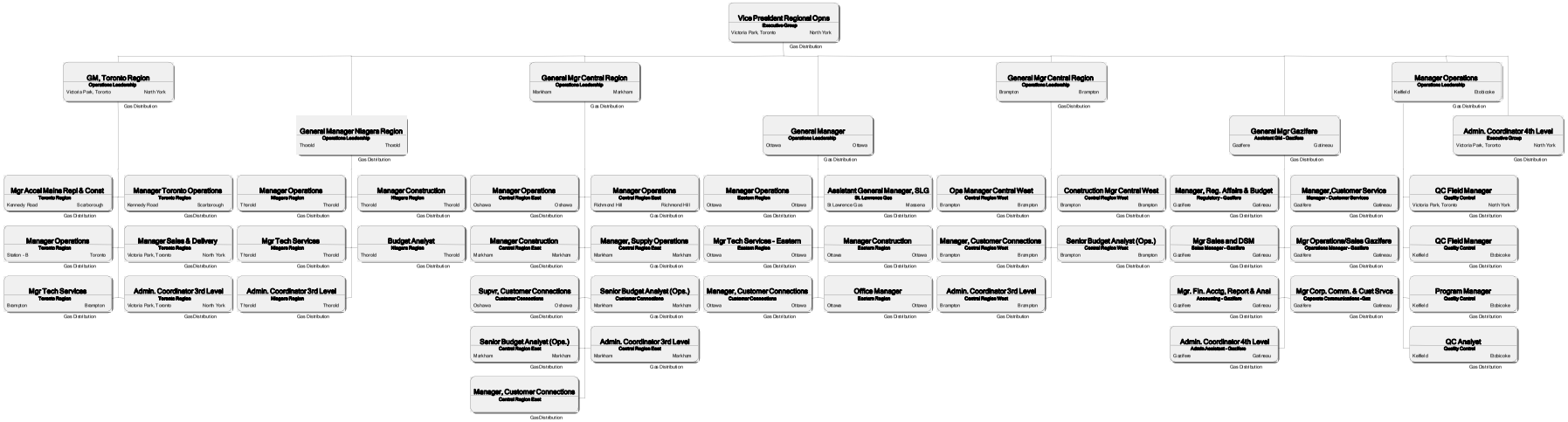
Current Date 11/7/2011




Current Date 11/9/2011

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Temp Employee
Contractor

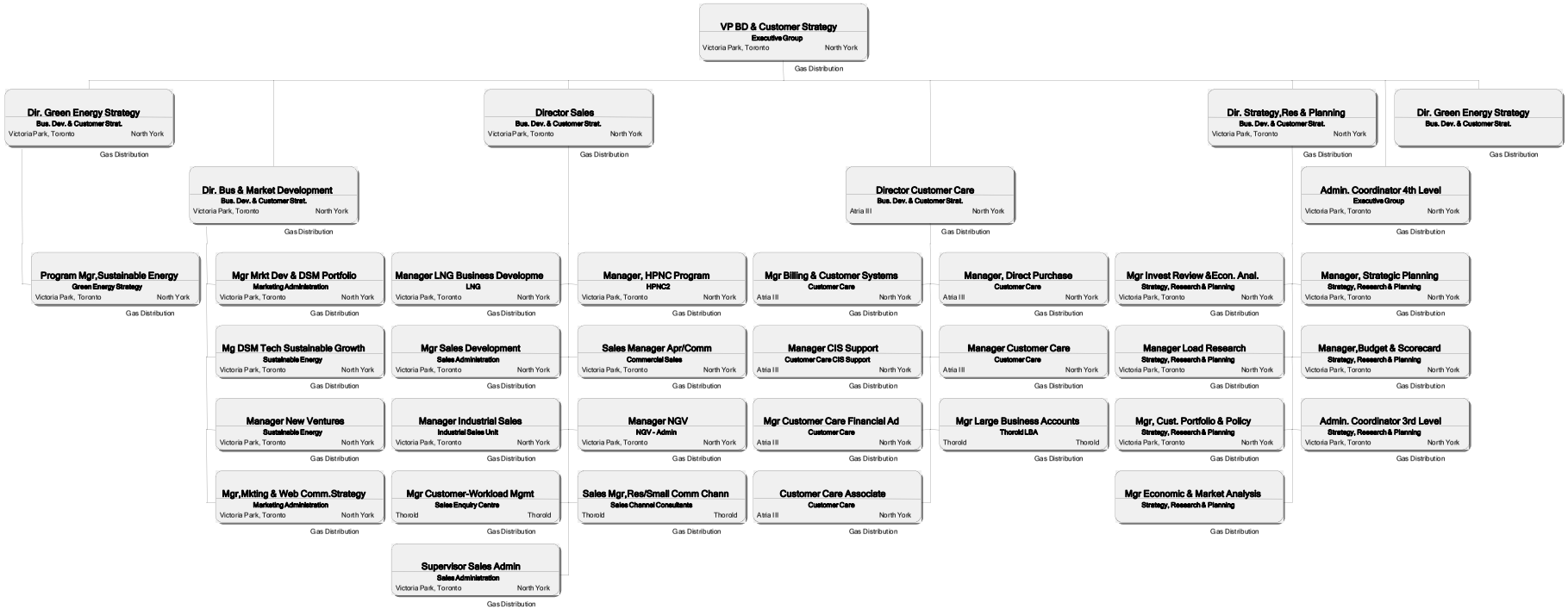
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Employee
Temp Employee
Contractor

Current Date 11/9/2011




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Current Date 11/9/2011

Employee
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Contractor

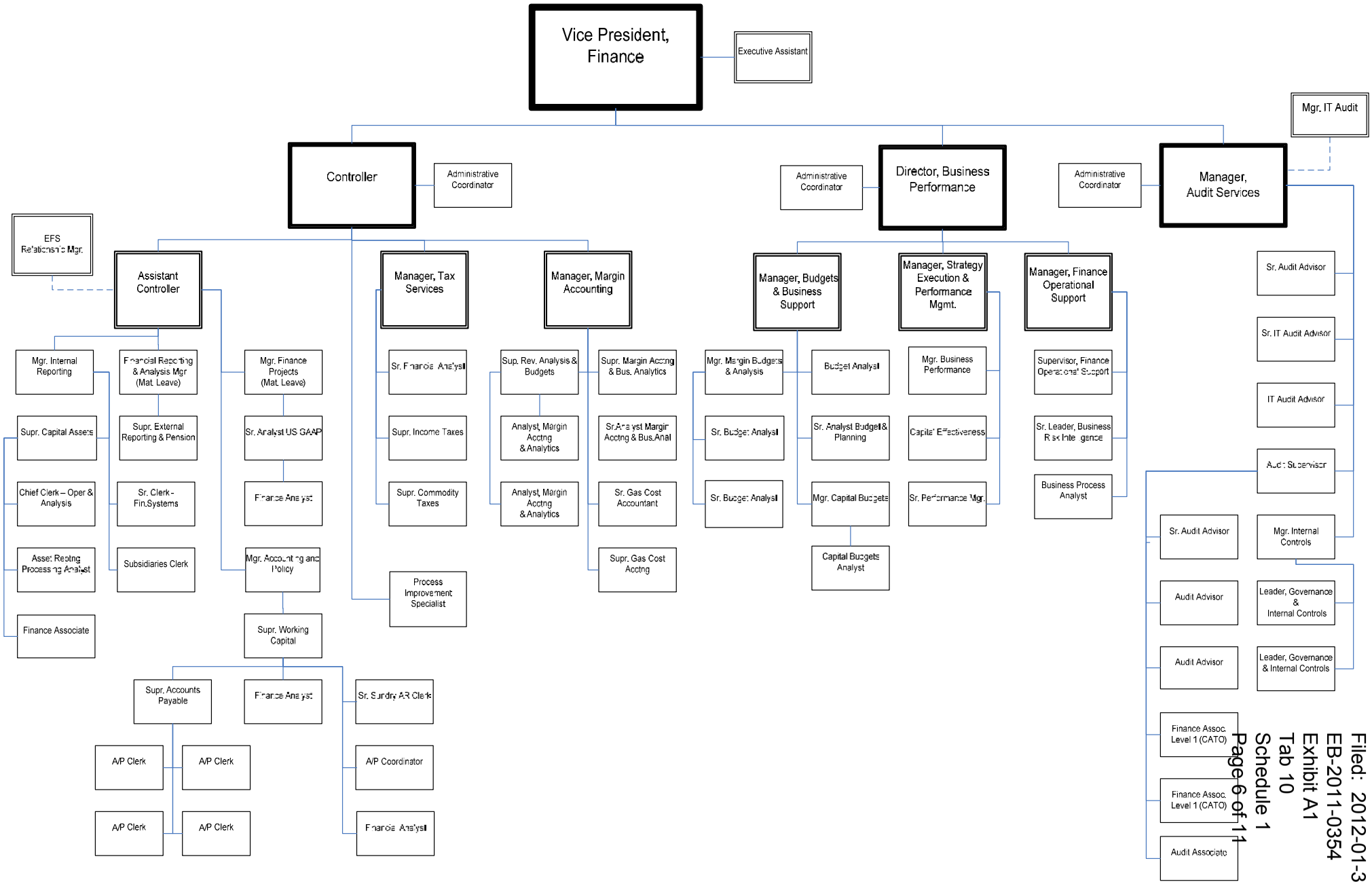


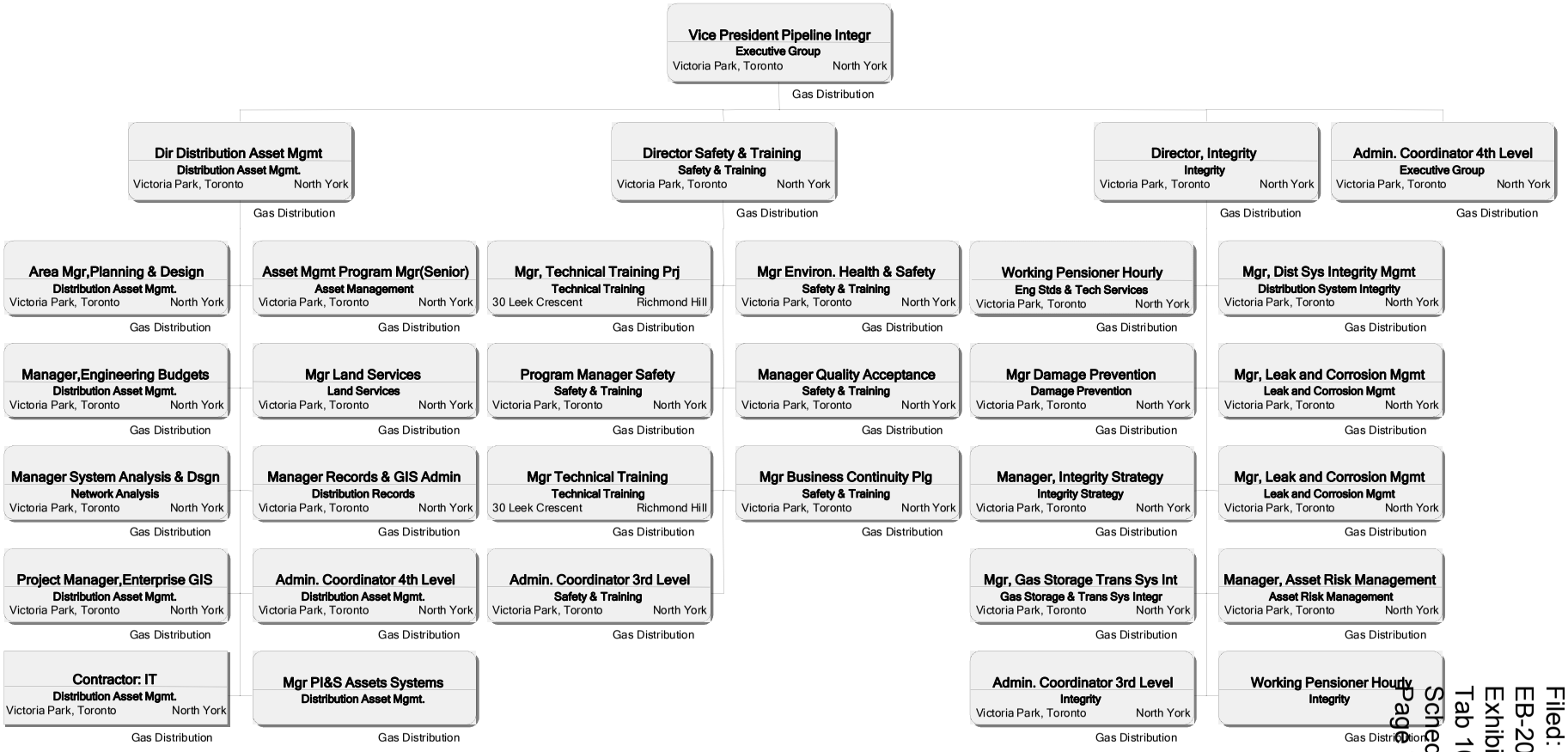

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Employee
Temp Employee
Contractor

Current Date 11/9/2011

# Gas Distribution - Finance





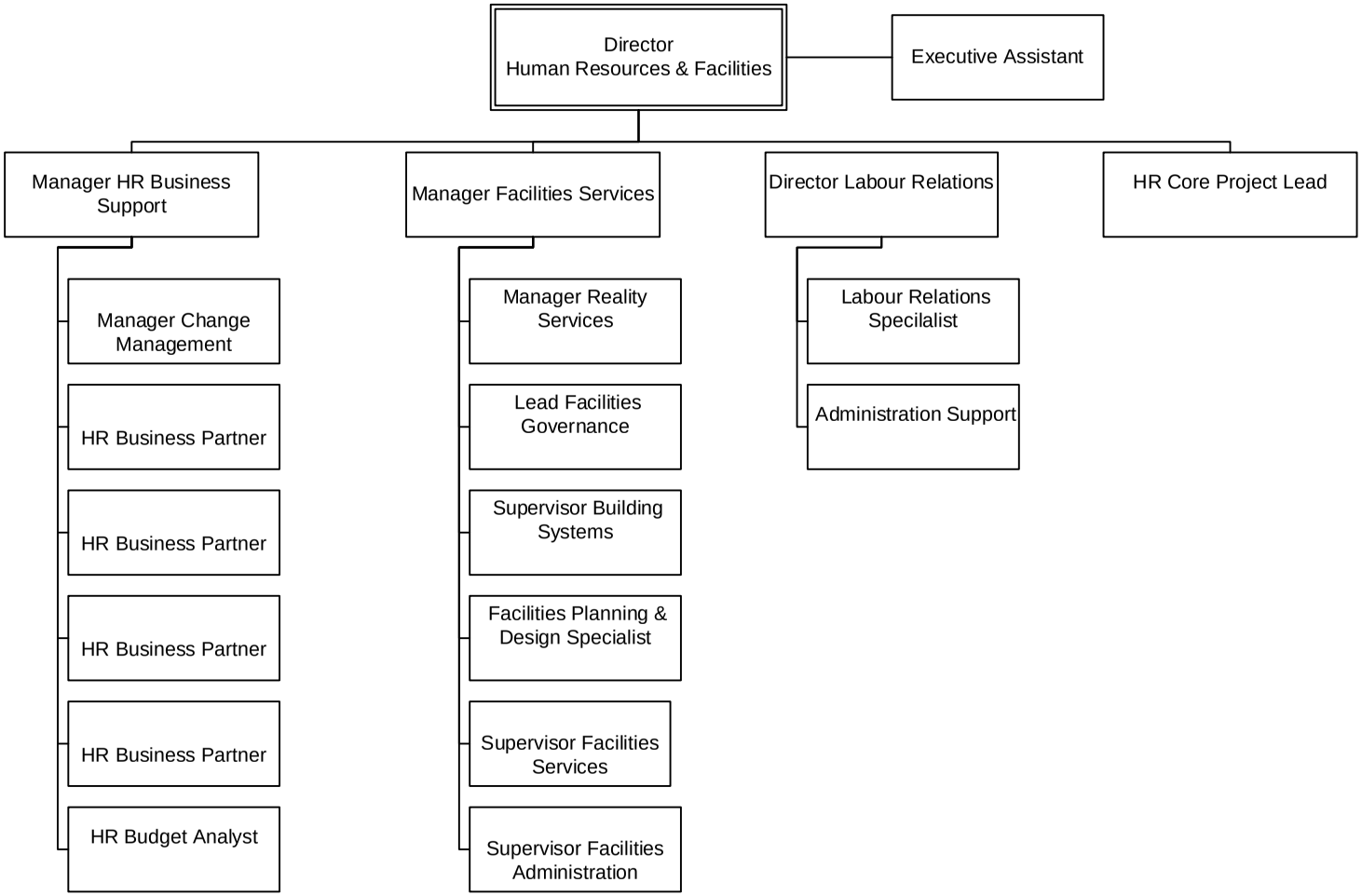

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Employee
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Contractor

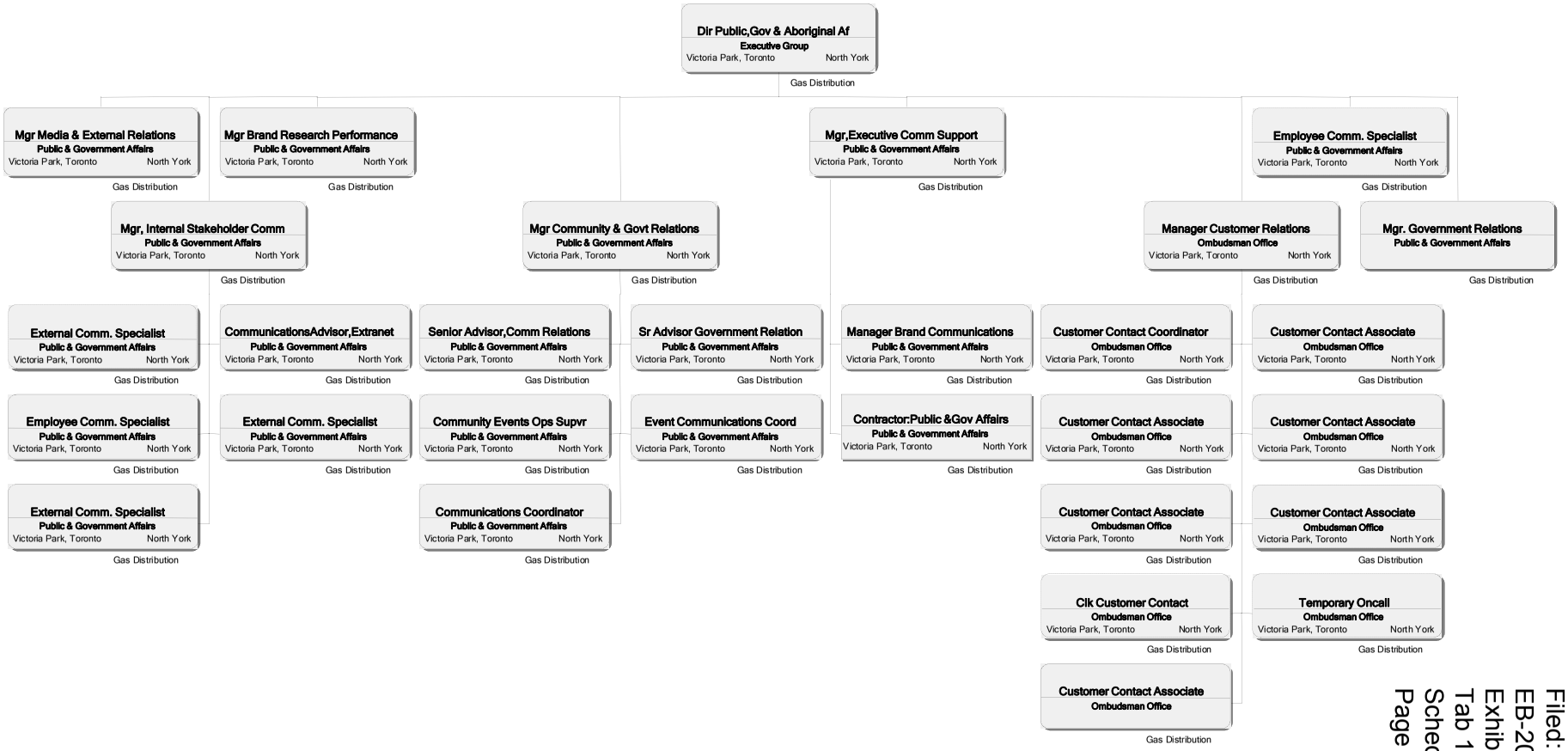
Current Date 11/9/2011

# Human Resources & Facilities

**October 2011**



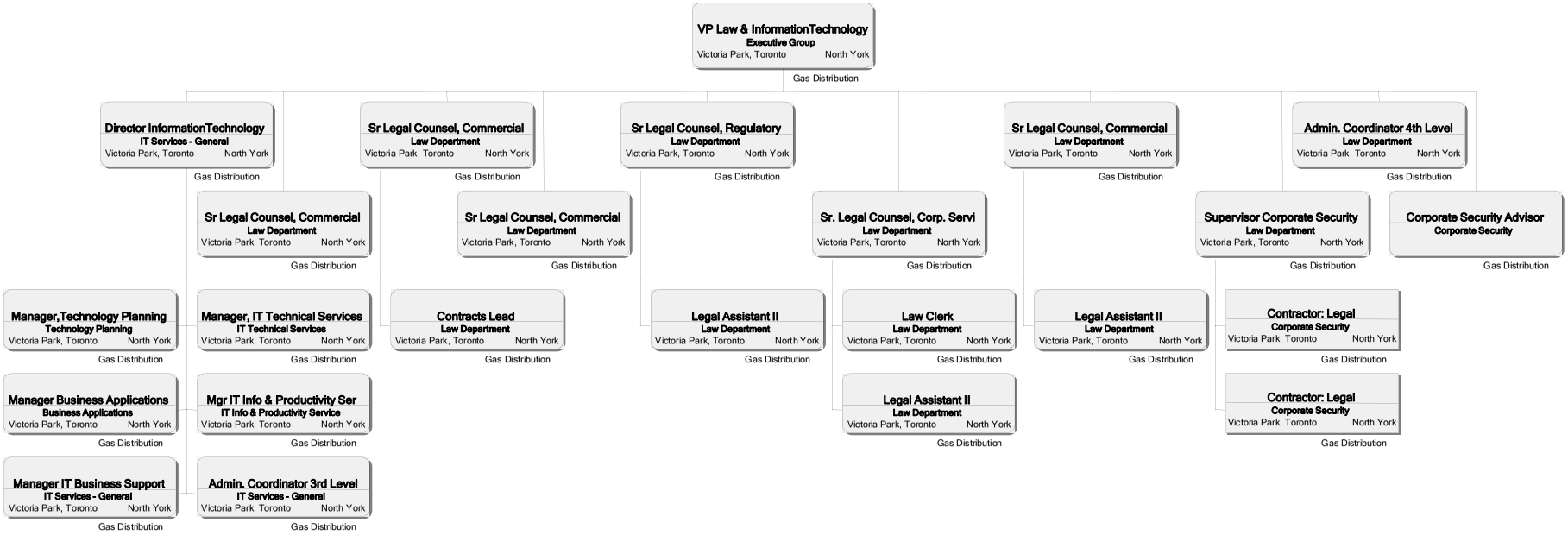

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EB-2011-0354
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Schedule 1
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Filed: 2012-01-31
EB-2011-0354
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Employee
Temp Employee
Contractor

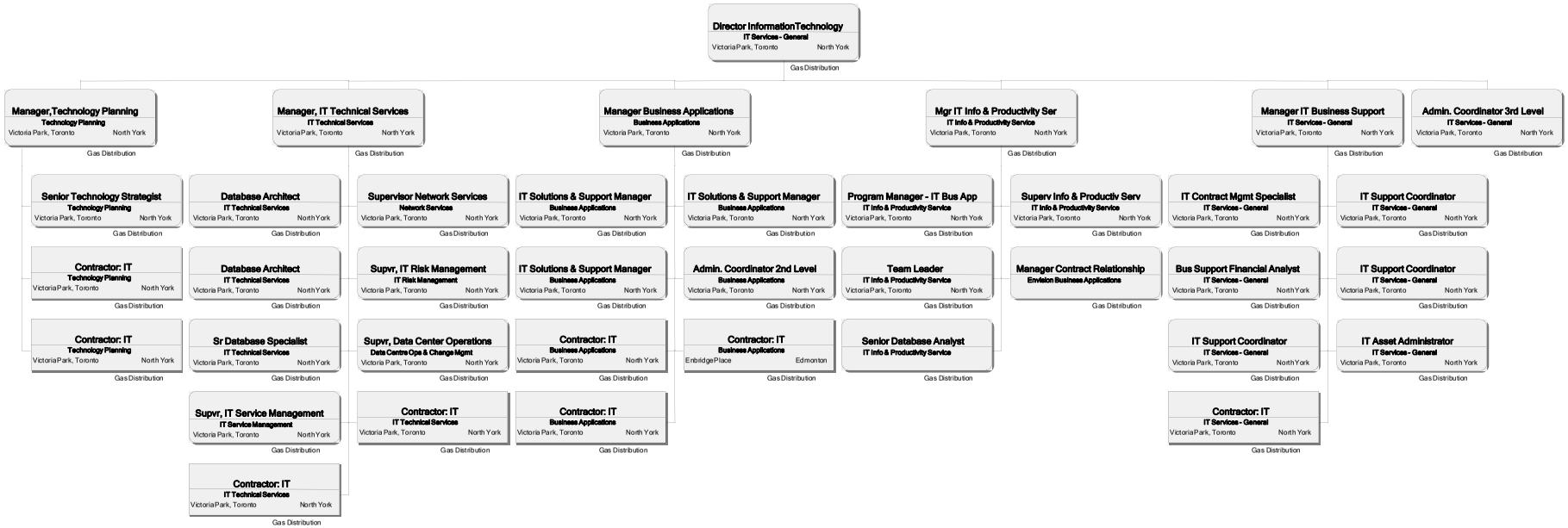
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Temp Employee
Contractor

Current Date 11/9/2011

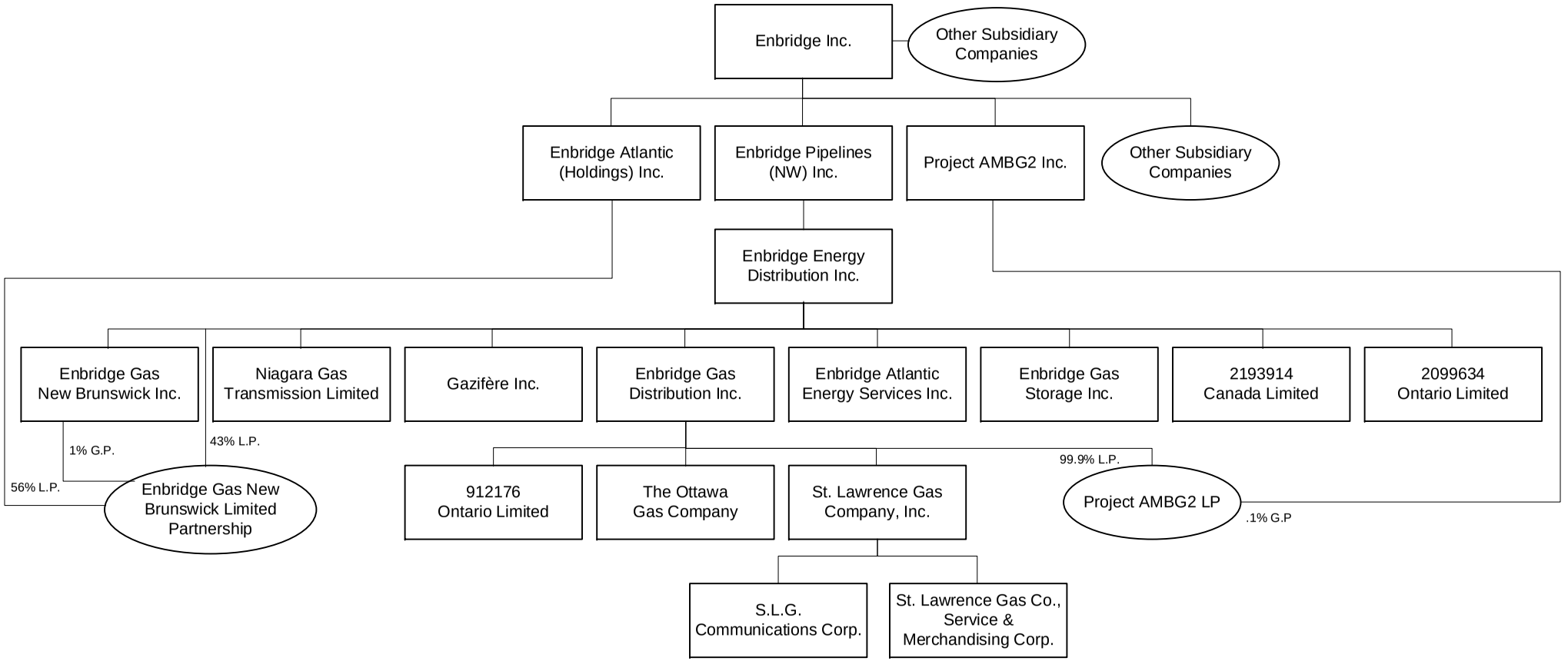



Filed: 2012-01-31
EB-2011-0354
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Employee
Temp Employee
Contractor

Current Date 11/10/2011

# Enbridge Gas Distribution Inc.
# Subsidiary & Affiliate Companies




Ownership is 100% unless otherwise noted

# PLANNED CHANGES IN CORPORATE OR OPERATIONAL STRUCTURE

1. There are no planned changes in corporate or organizational structure of the Enbridge Gas Distribution at the time of filing of this evidence exhibit.

Witness: J. Jozsa

# STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS AND / OR BOARD ORDERS

1. The IR Settlement Agreement (EB-2007-0615, Exhibit N1, Tab 1, Schedule 1), filed in this proceeding for reference purposes at Exhibit D2, Tab 10, Schedule 1, requires that, at the end of the five year IR term, EGD shall provide a full cost of service filing, including information required by the Board's minimum filing guidelines, as well as 2011 actual, 2012 bridge and 2013 forecast information and historical plant continuity information for 2006, 2007, 2008, 2009 and 2010. The prefiled evidence in this application meets the Company's obligations in this regard.

2. The 2010 ESM Settlement Agreement (EB-2011-0008, Exhibit N1, Tab 1, Schedule 1), filed in this proceeding for reference purposes at Exhibit D2, Tab 9, Schedule 1, established several obligations for EGD that were expected to result in the production of studies, reports and/or other information to be filed in this proceeding. Those obligations are referenced in paragraphs 3 through 15 which follow.

3. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, paragraph. n, on pages 11 and 12:

> All parties agree that while the 2010 costs and revenues related to Enbridge's High Performance New Construction Program ("HPNC") initiative with the Ontario Power Authority ("OPA") as set out in the contract dated January 7, 2008, are included in the 2010 ESMDA, the ratepayer share of the net revenues associated with the HPNC initiative shall be included within the Electric Program Earnings Sharing Deferral Account ("EPESDA") in 2011 and 2012, rather than in the ESMDA.

4. This obligation and the Company's compliance will be evident and subject to examination in the applications related to the 2011 ESM application anticipated to be filed in late March of 2012, and in the 2012 ESM application anticipated to be filed in late March of 2013.

Witness: R. Bourke

5. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, paragraph. n, on pages 11 and 12:

> Enbridge agrees that, as part of the evidence in support of its 2013 application, it will work with a third party consultant to prepare and file an updated study addressing the costs sought to be recoverable under the Regulatory Cost Allocation Methodology ("RCAM") for future years (2013 and beyond). Enbridge further agrees to engage with the existing RCAM consultative group as part of the development of the updated study. Notwithstanding any findings in this study, all parties agree that the clearance of the principal balance in the 2010 ESMDA is not subject to future review. All parties further agree that Enbridge may continue to use the current RCAM approach for the determination of RCAM costs for the balance of the IRM term.

6. The Company has engaged MNP LLP ("MNP") as the third party consultant to undertake the study referenced above. The MNP report will be filed at Exhibit D2, Tab 1, Schedule 1 when it is finalized.

7. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, paragraph. n, on pages 11 and 12:

> Enbridge agrees that it will file evidence in its 2011 Deferral and Variance Account clearance proceeding and also its 2013 application setting out the costs associated with activities undertaken within the Company related to distributed energy, green energy initiatives and fuel cells, and addressing the appropriateness of any eliminations from overall expenses related to those activities made for ESMDA determination purposes.

8. The Company has filed evidence at Exhibit D2, Tab 8, Schedule 1 to provide the requested material for the 2013 forecast of costs associated with the above referenced activities. Further, the Company's compliance for the 2011 and 2012 historical years will be evident and subject to examination in the applications related to the 2011 ESM application anticipated to be filed in late March of 2012, and in the 2012 ESM application anticipated to be filed in late March of 2013.

Witness: R. Bourke

9. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, paragraph. o, on page 13:

> Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study, prepared by an external expert (which may be an accounting firm), addressing whether the costs incurred to date, and forecast, by Enbridge to transition to IFRS or USGAAP are reasonable in comparison to other distribution utilities similar in size and/or complexity to Enbridge.
>
> Enbridge further agrees that, as part of the evidence in support of its 2013 application, it will file the capitalization study prepared by Ernst & Young in 2010, the costs of which are included in the 2010 IFRSTCDA.

10. The Company has engaged KPMG LLP ("KPMG") as the third party consultant to undertake the study referenced above addressing whether the costs incurred to date, and forecast, by EGD to transition to IFRS or USGAAP are reasonable in comparison to other distribution utilities. The KPMG report will be filed at Exhibit D2, Tab 7, Schedule 1 when it is finalized.

11. The capitalization study prepared by E&Y in 2010 entitled "Review of Enbridge Distribution Gas Distribution Overhead Allocations for IFRS", dated March 5, 2010 is filed at Exhibit D2, Tab 7, Schedule 2.

12. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, paragraph. r, on page 14:

> Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study addressing what steps gas distribution utilities are taking in regard to measuring, forecasting, controlling the variability and managing the amount of unaccounted for gas volumes, and to compare what Enbridge is doing in respect of these issues relative to other gas distribution utilities. Notwithstanding any findings in this study, all parties agree that the clearance of the principal balance in the 2010 UAFVA is not subject to future review and all parties agree that Enbridge may continue to use its current approach to managing, measuring and forecasting unaccounted for gas volumes for the balance of the IRM term.

13. The Company has filed the requested UAF report at Exhibit D2, Tab 6, Schedule 1.

Witness: R. Bourke

14. Reference: EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, Issue 3, on page 15:

> For the purpose of reaching an overall settlement, no party opposes Enbridge's allocation of costs between regulated and unregulated storage activities for the purposes of determining the 2010 ESMDA amount. There is no agreement as to whether Enbridge's continued use of its current approach to allocating costs between regulated and unregulated storage is appropriate for future years. Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study, prepared by an external expert, evaluating the appropriateness of the allocation of costs between Enbridge's regulated and unregulated storage activities. It is expected that the expert will provide a professional assessment of the methodologies used and recommendations for alternate approaches if, in their opinion, improvements can be made.

15. The Company has engaged Black & Veatch Management Consulting ("B&V") as the third party consultant to undertake the study referenced above. The B&V report will be filed at Exhibit D2, Tab 5, Schedule 1 when it is finalized.

16. In compliance with the RP-2003-0203 Settlement Proposal, EGD continues to report on the actual cost and benefits achieved related to the EnVision project on an annual basis. The report covering 2003 to 2010 actual was distributed to parties on October 28, 2011.

17. In compliance with a commitment from the NGEIR proceeding related to the provision of unbundled rates, EGD continues to report on a quarterly basis the number of customers that have contracted for service under Rate 300. The Company's last letter was distributed to parties on January 3, 2012.

18. The Customer Care / CIS Settlement Agreement ("CIS/CC settlement"), docket EB-2011-0226, Exhibit N1, Tab 1, Schedule 1 dated September 2, 2011 and filed for reference purposes in this proceeding at Exhibit D1, Tab 12, Schedule 2, contains commitments related to (1) the generation of new or additional revenue

opportunities and (2) cumulative capital costs related to new or replacement CIS system cost(s) greater than $50 million, neither of which are triggered in the 2013 Test Year. However, the Company has adjusted the forecast of cost(s) in the 2013 operating budget to reflect the 2013 agreed recovery amount (that is, the 'smoothed' 2013 amount) as per the CIS/CC settlement. The evidence related to the adjustment(s) to affect the appropriate recovery amount for the 2013 Test Year has been filed at Exhibit D1, Tab 12, Schedule 1.

19. The Company has been working towards the implementation of changes to its EnTRAC customer interface in order to facilitate the re-establishment of a customer's MDV mid-year, at their discretion, as agreed in the EB-2008-0106 proceeding. The MDV project team is expecting to meet the targeted implementation date of January 31, 2012.

20. In the System Reliability Settlement Agreement (EB-2010-0231, Exhibit C, Tab 1, Schedule 1, dated July 19, 2010), the Company committed to provide a report on curtailment compliance in its 2013 rate application. That report has been filed at Exhibit D1, Tab 2, Schedule 4.

21. The changes that have been prescribed to the Customer Service Rules in the EB-2010-0280 proceeding and other related dockets have been or will be implemented within the Board's 'coming into force' date. The Company has communicated with parties on multiple occasions the most recent of which includes the distribution of a Company submission on December 22, 2011 with the Company's Conditions of Service statement attached, and in the 2012 rate application in response to VECC interrogatory #14 (EB-2011-0277, Exhibit I, Tab 8, Schedule 14, dated November 16, 2011).

Witness: R. Bourke

22. The Board-approved Settlement Agreement in the EB-2009-0043 Open Bill Services application (Exhibit N1, Tab 1. Schedule 1) provides, at page 7 of 14, that if EGD intends to continue the provision of Open Bill Services past December 31, 2012, it will file application with the Board. Enbridge's evidence and proposal to continue Open Bill Services is filed at Exhibit D1, Tab 9, Schedule 1.

23. At the time of filing this 2013 rate application, there are other open or anticipated proceedings which may or may not result in further obligations for the Company that could possibly fall within the 2013 application and hearing time frame. For example (this list is illustrative and not exhaustive);
    a. The 2012 rate application (docket EB-2011-0277) in which the unsettled issues are to be heard beginning on January 24, 2012;
    b. The DSM Multi-Year Plan 2012-2014 application (docket EB-2011-0277); and
    c. The 2011 ESM and Deferral Account clearing application which is anticipated to be filed in late March, 2012.

# CONDITIONS OF SERVICE

1. The Ontario Energy Board ("Board") issued amendments to the Gas Distribution Access Rule ("GDAR") on October 14, 2011. As per section 8.2.1 of GDAR, the Company published its Conditions of Service which describes Enbridge's operating practices and policies with respect to gas distribution services and customer service. The Conditions of Service as published on the Company's website at enbridgegas.com/ConditionsofService are presented in Appendix A.

# ENBRIDGE GAS DISTRIBUTION INC.

## CONDITIONS OF SERVICE

**JANUARY 1, 2012**

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   2.3. Interruptions in Gas Distribution and/or Supply 5
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# Preface

As Canada's largest natural gas distribution company, Enbridge Gas Distribution ("Enbridge") has been providing natural gas services in a safe and reliable manner for more than 160 years, and currently provides service to approximately 1.9 million homes and businesses.

These Conditions of Service describe in summary form Enbridge's operating practices and policies, and are provided as part of our commitment to providing our customers with safe and reliable gas services.

We reserve the right to modify the contents of the Conditions of Service at any time. These Conditions of Service are meant as guidelines and do not supersede any terms and conditions agreed to in our contracts for gas supply with you.

# 1. Enbridge Franchise Area and Gas Distribution Services

The following is a list of cities and towns that Enbridge provides distributions services to.

***Eastern Region***

Admaston
Alfred & Plantagenet
Arnprior
Beckwith
Brockville
Carleton Place
Casselman
Champlain
Clarence-Rockland
Deep River
Drummond-North Elmsley
Elizabethtown-Kitley
Hawkesbury
Horton
Laurentian Hills
Laurentian Valley
Leeds and Grenville
McNab-Braeside
Merrickville-Wolford
Mississippi Mills
Montague
North Glengarry
North Grenville
North Stormont
Ottawa
Pembroke
Perth
Petawawa
Renfrew
Rideau Lakes
Russell
Smiths Falls
South Glengarry
Tay Valley
The Nation
Whitewater Region

***Central Region***

Adjala
Ajax
Amaranth
Asphodel-Norwood
Athens
Aurora
Barrie
Bradford-West Gwillimbury
Brampton
Brighton
Brock
Caledon
Cavan Monaghan
Clarington
Clearview
Collingwood
Douro-Dummer
Dufferin
Durham
East Garafraxa
East Gwillimbury
East Luther Grand Valley
Erin
Essa
Georgina
Grey Highlands
Havelock Belmont Methuen
Innisfil
Kawartha Lakes
King
Markham
Melancthon
Midland
Mississauga
Mono
Mulmur
New Tecumseh
Newmarket
Orangeville
Oshawa
Otonabee S- Monaghan
Penetanguishene
Peterborough
Pickering
Richmond Hill
Scugog
Severn
Shelburne
Smith-Ennismore-Lakefield
Southgate
Springwater
Tay
Tiny
Toronto
Trent Hills
Uxbridge
Vaughan
Wasaga Beach
Wellington
Whitby
Whitchurch

***Niagara Region***

Fort Erie
Grimsby
Lincoln
Niagara Falls
Niagara-on-the-Lake
Pelham
Port Colburne
St. Catharines
Thorold
Wainfleet
Welland
West Lincoln

# 2. Gas Distribution Services

## 2.1. Gas Supply and Delivery

Gas will be delivered and/or supplied to our customers within our franchise area subject to these Conditions of Service and to the provisions of Enbridge's rate schedules, under the following circumstances:

- there is sufficient supply of gas;
- there is sufficient capacity in Enbridge's distribution system; and,
- the supplying and/or delivering of gas is economically feasible.

## 2.2. Gas supply and/or delivery under more than one rate schedule

Gas may be supplied and/or delivered under more than one rate:

- Provided the customer meets all the applicability requirements of each rate schedule as approved by the Ontario Energy Board. Gas supplied and/or delivered under each rate schedule will normally be metered separately but may be taken through one meter provided:
    - Enbridge and the customer agree in writing upon a formula for determining the supply and/or delivery service that the customer will purchase under each rate schedule.

## 2.3. Interruptions in Gas Distribution and/or Supply

Customers may be required to curtail or discontinue the use of gas if the supply of gas is jeopardized by any of the following:

- in the event of actual or threatened shortage of gas due to circumstances beyond the control of Enbridge; or,
- when curtailment or restriction is ordered by any government or agency having jurisdiction.

Enbridge shall not be liable for any loss of production, nor for any damages whatsoever due to curtailment or discontinuance, nor because of the length of advance notice given to customers regarding curtailment or discontinuance.

## 2.4. Force Majeure

Customers of Enbridge shall not have any claim against Enbridge for damages sustained as a result of the interruption or cessation of gas deliveries caused by force majeure which include:

- acts of God, the elements;
- labour disputes, strikes, lockouts;
- fires, accidents;
- the breakage or repair of pipelines or machinery;
- depletion or shortage of gas supply;
- order of any legislative body or duly constituted authority; or,
- any other cause or contingencies beyond the control of Enbridge.

# 3. Rate Schedule

## 3.1. Changes in Rate Schedules

In the event the Ontario Energy Board amends the rate schedules of Enbridge, the amended price or amended terms and conditions shall apply to services provided under the rate schedules after the effective date established by the Ontario Energy Board.

# 4. Initiation of Service

## 4.1. Main Extensions

Enbridge will extend its gas main within its franchise area to serve new customers when it is feasible to do so. Enbridge will look at the following when determining feasibility:

- the number of potential new customers within the next five years;
- the amount of natural gas to be used; and,
- the cost of extending the gas main.

If the cost of the extension is not economically feasible, the applicant/s will be required to pay a contribution in aid of construction. Enbridge will determine the contribution amount and communication will be provided to the applicant/s in writing.

## 4.2. Service Installations

Enbridge reserves the right to designate the location at which the service will enter a building. The normal point of entry will be through the wall nearest to the gas supply. Where no additional cost is involved, the service may be installed to accommodate requirements of the applicant for service.

For residential service, Enbridge will usually install a service at no charge to the applicant, provided the service installed is 20 metres in length measured from the property line to a point of delivery up to 2 metres beyond the front building wall. For residential and non residential service, the cost of the service in excess of the cost of a normal residential service of 20 metres in length, and any length exceeding 2 metres beyond the front building wall, may be charged to the applicant.

Where an applicant for gas service requests an installation on property that is not owned by the customer such as road allowance, municipal or neighboring property, land rights (in the form of an easement) from the property owner will be required for the installation and maintenance of all necessary gas lines and equipment.

Enbridge will try to restore property to the approximate condition in which it was found before starting our operations. This includes property that is excavated or may be disrupted during laying, constructing, repairing or removing our facilities.

## 4.3. Location of Meter and Service Regulators

Enbridge shall supply each customer with a meter of a size and type that will adequately measure the gas supplied. Enbridge shall:

4.3.1. Make every effort to install meters and service regulators so as to be at all times accessible for inspection, reading, testing, maintaining and exchanging.

4.3.2. Not install meters in locations prohibited by law. The following locations are specifically prohibited:

- under combustible stairways;
- unventilated areas;
- inaccessible areas; or,
- within 90 cm (3 feet) of a source of ignition.

4.3.3. Install all meters outside the building to which gas is supplied except in rare circumstances where it is not practical.

4.3.4. Provide protection where outside meters and regulators are installed in locations that do not afford reasonable protection from damage.

Anyone who is not an authorized agent of Enbridge shall not be permitted to connect or disconnect our meters or regulators, nor shall any piping be connected to or disconnected from Enbridge's facilities except by representatives of Enbridge.

Customers are responsible, subject to the provisions of paragraph 4.3.4, for protecting all metering and regulating equipment necessary for the supply of gas and for keeping it accessible at all times.

## 4.4. Alterations

Alterations or service relocation requests will be dealt with as follows:

- The cost of work done to relocate existing equipment solely for the convenience of the customer will be charged to the customer.
- The undepreciated cost of any equipment abandoned as a result of relocation for the customer's convenience, or replacing equipment to increase their capacity to accommodate a customer's increased requirements, may be charged to the customer.

## 4.5. Customer Responsibilities regarding Building Piping Appliances & Equipment

As an applicant for service, a customer shall:

- at their own expense install, all piping, controls, safety devices, and other attachments necessary from the meter to the equipment or appliances served;
- ensure the building piping, appliances, and equipment are installed in accordance with regulations made under the authority of statutes passed by the Province of Ontario establishing the requirements for the installations of such facilities; and,
- be responsible for maintaining all building piping, appliances and equipment in a good and safe condition. Such maintenance will be at the customer's own expense.

If there is a leakage or escape of gas on a customer's premise, the customer is required to notify Enbridge immediately by calling our Emergency number at 1-866-763-5427.

Enbridge shall not be liable to the customer for any damages. The customer shall indemnify Enbridge from and against all loss, costs, damages, injury, or expense associated with any injury or damage to persons or property arising, either directly or indirectly, from or incidental to the escape of gas or products of combustion of gas from building piping, venting systems or appliances on the customer's side of the point of delivery.

For the purpose of inspecting or repairing or of altering or disconnecting any service pipe within or outside the building, the customer shall ensure that free access is permitted to Enbridge at all reasonable times, and upon reasonable notice given and request made, to all parts of every building or other premises to which gas is supplied.

## 4.6. Inspections of New Installations

All inspections shall conform to the Technical Standards and Safety Act and regulations made under the Act. All new installations of supply piping, gas appliances and installations will be inspected prior

to gas being introduced to a building in accordance with the requirements of the Technical Standards and Safety Act and the regulations made under the Act. If the inspection reveals that repairs or adjustments are required, the customer will be advised and repairs or adjustments will need to be corrected prior to the gas being turned on.

# 5. Maintenance of Service

## 5.1. Turning Off and Turning on Gas Supply

In an emergency, the gas supply to appliances may be turned off in the interest of safety. Only a qualified person holding an appropriate certificate from the Regulatory Authority having jurisdiction may turn on the supply of gas to appliances which have been turned off.

Except in the case of a notification of a hazard, the turning on and off of the gas supply for purposes of installing, servicing, removing or repairing gas appliances may only be done by a person certified to perform this work by the Regulatory Authority having jurisdiction.

## 5.2. Meter Exchange and Testing

### 5.2.1. Meter Exchange

Under Government of Canada regulations (Section 12 of the Electricity and Gas Inspection Act), Enbridge is required to periodically exchange gas meters for government inspection.

To complete the meter exchange, we will shut off the gas supply to your existing meter, replace it with a new meter and then relight and inspect all of your natural gas equipment.
There is no charge for this service. If we are required to exchange your meter we will contact you via letter or telephone. Please call the number provided at the time of contact to make an appointment. The inspector who comes to your property will carry valid Enbridge photo ID and you may ask to see it before providing access.

### 5.2.2. Meter Testing

Should a meter fail to register the amount of gas used, consumption shall be estimated by Enbridge and supply and/or delivery charges shall be paid for by the customer in accordance with such estimate.

Should a customer dispute the accuracy of a meter, an application for a Government Inspection of the meter in accordance with the Electricity and Gas Inspection Act may be made. If, after the test, the meter is found to register with an error greater than that permitted by regulations, such error shall be held to have existed for a period of three months or from the date on which the meter was last sealed if the said sealing took place within three calendar months of the request. In the event of the meter being more than three months past due for re-verification, Enbridge or the customer, as the case may be, is entitled to the amount represented by the full error of the meter from the date on which it should have been re-verified. All costs involved in effecting this test shall be borne by the party against whom the decision is given.

In the event of an erroneous connection or incorrect use of an apparatus, the error shall be deemed to have existed from the time of connection.

In the event it can be, through records, determined when an error occurred, the bill will be retroactive to that time.

# 6. Customer Service

For the purposes of this section, “customer” means a residential customer (referred to as “you” in this section).

In accordance with Enbridge’s submission to Ontario Energy Board regarding Gas Distribution Access Rule customer service standards for natural gas distributors, Enbridge will be revising its policies and practices and amending its Conditions of Service by September 30, 2012.

## 6.1. Setting up an Enbridge Account

Whether you are a first time customer to Enbridge or moving from an existing Enbridge account, you should notify us before taking possession of a new home. Enbridge requires at least 3 business days (including Saturdays) advance notice of a move. If advance notice is not given Enbridge will only retroactively adjust the account for a maximum of 30 days from the date notification is received.

On our website you will find information on how to submit a “First Time Customer” form or a Move request or you can call the Enbridge Call Centre at 1-877-362-7434.

As an Enbridge customer you will be expected to comply with the Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to your premises. These Conditions of Service will remain in effect until Enbridge has accepted and completed your request for termination or until we have processed your move request.

## 6.2. Meter Reading

Enbridge reads your meter every other month and will estimate your consumption based on your historical gas usage in between readings. If Enbridge’s representative is unable to read the meter, a bill will be issued based on an estimated reading. If Enbridge has been unable to read a meter during normal working hours, arrangements will be made to obtain a reading at the customer’s convenience. You can also submit your own meter reading using the Submit Meter Reading Form on our website or alternatively, you can call the Enbridge Call Centre at 1-800-268-5442.

## 6.3. Security Deposits

Security deposits are collected to secure payment for future charges in the event of a customer not paying their bill. To protect against losses, Enbridge reserves the right to request a security deposit from its customers as a condition of supplying gas service. A security deposit may be required if you are a first time Enbridge customer, or if you have not been able to maintain a good payment history.

All new residential customers are subject to a security deposit, unless they meet one of the waiver criteria outlined below. If you are required to pay a security deposit an amount of $250.00 will be charged on your next gas bill. Payment of the security deposit is required by the Late Payment Effective Date on the bill.

Enbridge will waive your security deposit requirement if you meet any of the following criteria:

- If you have moved and your previous account is in good standing;
- If you choose to sign up for our Pre-Authorized Payment Plan; or
- If you can provide a reference letter from another utility in Canada dated within the past 60 days.

Enbridge will review all security deposits on a monthly basis from the date the deposit is fully paid. If you have paid a security deposit, it will be refunded once you have demonstrated good payment history for a period of 12 months. Your security deposit will be returned with interest as a credit on

your next gas bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Good payment history is maintained unless you have experienced any of the following:

- Receipt of a disconnection notice from Enbridge;
- A payment you provided to Enbridge has been returned for insufficient funds; or
- Your gas has been turned off due to non-payment.

Interest earned on your security deposit will be paid upon return of all or any part of the security deposit or at the time you close your account, whichever comes first. Simple interest will be earned on all security deposits except those held for a total of six months or less. The interest rate applicable to security deposits in any year will be established quarterly and will be based upon the Ontario Energy Board prescribed interest rates. Interest is calculated retroactively to the date the security deposit was received.

Security deposits are not to be considered as prepayments for future charges.

## 6.4. Bill Issuance and Payment

### 6.4.1. Your Monthly Bill

Enbridge charges you the following charges on a monthly basis:

- **Monthly Customer Charge**
  Enbridge has a minimum charge per gas meter to help recover a portion of the fixed costs that the company incurs to keep the system ready for customer use at all times. These fixed costs (such as 24-hour emergency service, meter reading, pipeline maintenance and customer support services) do not vary with the amount of gas used.

- **Transportation to Enbridge**
  This charge is for the cost of transporting natural gas to distribution facilities in Ontario, including tolls.

- **Delivery to You**
  Once natural gas is received by Enbridge, these are the costs to safely and reliably deliver natural gas to our customers.

- **Gas Supply Charge**
  The charge for natural gas itself varies with the amount of gas used by each of our customers. You can choose to have your gas supplied by Enbridge Gas Distribution or an independent marketer. The rates that Enbridge charges for gas used are regulated by the Ontario Energy Board.

There are other charges that may appear on your bill from time to time based on events that occur with your account. These include:

- **New Account Charge**
  If you open a new account with Enbridge, the first bill will include a one time service charge of $25.00, to help cover the costs of setting up the account, taking a meter reading and related work.

- **Late Payment Effective Date/Late Payment Charge**
  Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. Customers are provided a period of 17 days to make a payment before a Late Payment Charge is applied to their account.

When payment in full of the Enbridge invoice is not received on or before the "Late Payment Effective Date" on the bill, a late payment charge will be incurred on the next bill. A charge of 1.5% per month (19.56% effectively per annum) on all of the unpaid charges, including all applicable federal and provincial taxes, will be applied to the account.

Late payment charges are not applied to security deposits amounts owing.

- **Adjustments**
  Your bill may show adjustments to charges from time to time when there is a correction made on your account.

For more information on the charges that appear on your bill, visit the Understanding Your Bill section on our website.

### 6.4.2. Charges from Other Companies

The Enbridge Billing Service allows other energy companies to include their charges on the Enbridge bill. If you have purchased a product or service from a participating company, the charges would appear in the section called "Charges From Other Companies" on your Enbridge bill.

This service helps make paying bills more convenient for you. You receive one bill and make one monthly payment to Enbridge Gas Distribution. This service also helps to keep rates low by sharing costs with other billers.

### 6.4.3. Billing from a licensed energy marketer

If you buy your natural gas supply from a licensed energy broker, your gas supply charges, along with the name of the licensed energy broker will appear in the 'Charges For Gas' section of your Enbridge bill.

### 6.4.4. Billing Options

- **Paperless Billing** 


Enbridge offers customers an environmentally friendly and secure bill delivery option in the form of a paperless bill. You can view and store up to 24 months of bills electronically through this service.

- **Budget Billing Plan**

The Enbridge Budget Billing Plan (BBP) provides all residential gas heating customers the convenience of paying equal amounts throughout the year and avoiding higher bills in winter months. Using your prior year's gas usage, Enbridge forecasts the amount of gas you will use and applies the current gas price to determine your monthly BBP installment.
The BBP season runs from September to July each year. In July, Budget Billing Plans are reviewed and reconciled and customers are billed or credited a BBP Final Adjustment that represents the difference between the charges for gas actually used from the time you join the plan and the monthly BBP installments billed to date. In the month of August, you are billed for the actual gas used in the month. The new plan then starts again in September.

Should a credit balance result after the annual reconciliation, the amount will be credited to your account and will appear on your July bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Should a chargeable balance result after the annual reconciliation, the amount will be charged to your account and will appear on your July bill. In the event that the BBP Final Adjustment charge is higher than expected, you may choose to call the Enbridge Call Centre at 1-877-362-7434 and one of our Customer Service Representatives will work with you to determine suitable payment arrangements.

At a minimum, one mid-season BBP review will occur usually at the beginning of the next calendar year. The mid-season review will recalculate your monthly BBP installment to ensure accuracy as weather, usage and rate changes could affect the actual charges for gas you use. After the mid-season review, the new monthly installment amount will be billed on your next bill and a bill message will explain that there was a review of your monthly BBP installment. **Customers are encouraged to monitor their BBP details (actual gas charges billed to date versus BBP installments billed to date) and may request a review at any time.**

A number of factors can create a variance in the plan. Significant changes in weather, gas prices, change in gas marketers, or gas use in the home, such as installing a new natural gas appliance, can create a difference between actual gas costs and installment amounts.

First time gas customers are automatically assigned to the BBP unless they request otherwise.

### 6.4.5.Payment Options

- **Pre-Authorized Payment**

Enbridge also offers a Pre-Authorized Payment Plan. Signing up for the Pre-Authorized Payment Plan will allow your amount due to be automatically withdrawn from your bank account on the day before the Late Payment Effective Date.

- **Other payment options include:**

  - Online or in person at a financial institution

  - Telephone Banking

  - Credit Card
    For a Credit Card Convenience fee of $2.85 for every $150 charge paid to our Credit Card Service Provider, you may use a valid credit card to make a payment.

  - Western Union
    For customers with overdue amounts that are at or nearing disconnection for non-payment, you may choose to make a payment for a fee through Western Union.

  - Standard Mail
    You can send a cheque or money order (no cash please), along with the bottom tear-off portion of your bill, to:

    Enbridge
    P.O. Box 644
    Toronto, ON M1K 5H1

Please make your cheque payable to "Enbridge" and write your account number on the front.

- Pay in Person
  You may also drop your payment off at one of our payment drop boxes located in the following locations 24 hours a day:
  (Please note: for your security, we cannot accept cash at these offices.)

  VPC Office
  500 Consumers Road
  North York, Ontario

  Ottawa Office
  400 Coventry Road
  Ottawa, Ontario

  Thorold Office
  3401 Schmon Parkway
  Thorold, Ontario

## 6.5. Correction of Billing Errors

Retroactive billing ensures that all gas consumption and other Enbridge charges, not billed previously, are billed correctly to the customer. Retroactive billing can be the result of either a customer error or a company error. When a customer has been billed incorrectly, retroactive billing is required.

Where billing errors, either through company or customer error, have resulted in either under or overbilling, the customer will be charged or credited with the amount erroneously billed for a period not exceeding two years.

If you have been underbilled, Enbridge will work with you to determine a suitable payment arrangement.

## 6.6. Discontinuance of Gas Supply or Delivery

### 6.6.1. Customer Initiated Discontinuance

A customer will continue to be bound by these Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to the premises along with any other monthly charges applicable including late payment penalties until Enbridge has terminated the supply of gas following the acceptance of a request for termination from the customer.

### 6.6.2. Emergency or Safety related Discontinuance

Enbridge may discontinue gas supply and/or delivery to any customer for any of the following reasons:

- for use of gas for any purpose other than that described in the service application, gas supply contract, or rate schedule;
- in case Enbridge, is refused access for any lawful purposes to the premises to which gas is supplied and/or delivered;

- when Enbridge property on a customer's premises is in any manner tampered with, damaged, or destroyed;
- when Enbridge has reason to believe that an unsafe condition exists on the premises or may develop from a continuation of gas supply and/or delivery;
- when a gas installation contravenes the provisions of the Technical Standards and Safety Act, associated regulations, or any other applicable enactment; or
- when there is evidence of gas theft.

Discontinuance of gas supply and/or delivery for any of the reasons set out in paragraph 6.6.2 shall result in a disconnection charge payable by the Customer.

**6.6.3.Discontinuance of Service for Non-payment**

Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. If, for any reason, you are unable to make full payment you are encouraged to contact Enbridge to make suitable payment arrangements. Customers can call the Enbridge Call Centre at 1-877-362-7434.

If the bill is not paid in full and you have not contacted Enbridge to make payment arrangements, under the Public Utilities Act, Enbridge has the right to discontinue gas service. Prior to discontinuance of gas service Enbridge will provide a minimum 48 hours notice in writing along with a call to advise when the disconnection will occur.

If you are seeking payment assistance through a registered charity, government agency, social service agency or a third party, you must provide consent to Enbridge to provide details of your account to these third parties. Enbridge will place any disconnection or collections actions on hold and will work with the third party to obtain payment to avoid disconnection of your gas service.

If your meter has been turned off for non-payment, when payment in full is received by Enbridge including any disconnection charges and security deposit, Enbridge will reconnect your gas meter within 48 hours.

## 6.7. Arrears Management Programs

Enbridge has different arrears management programs available to customers who are unable to pay their entire bill. Enbridge works with customers depending on their individual circumstances to come up with a mutually agreeable payment arrangement. Customers requiring assistance are encouraged to call the Enbridge Call Centre at 1-877-362-7434 to discuss options.

In the event that you are having difficulty paying your bill, emergency financial assistance is also available. The Ontario Energy Board has initiated the Low Income Energy Assistance Program which operates similar to our Winter Warmth Program and provides financial assistance to families in need. You can choose to apply for financial assistance through various community agencies. Disconnection of gas service is always a last resort.

## 6.8. Allocation of Payments between gas and non-gas charges

Payments are applied to your gas bill charges based upon the oldest billed amounts being paid first. In the event that payment is insufficient to cover all charges invoiced in a month, payments will be allocated to non-gas charges first, unless otherwise notified of a dispute. Any charges that remain outstanding past the late payment effective date will incur a late payment charge as mentioned in the Bill issuance and Payment section.

## 6.9. Management of Customer Accounts

Enbridge is committed to providing excellent service and to ensuring that relationships with customers are conducted with integrity and in a responsible, fair, honest and ethical manner. Consistent with these objectives Enbridge maintains high standards of confidentiality with respect to the personal information in its possession. Any personal information related to a customer's account will only be shared with the party named on the account or any third party designated by the customer. To provide consent for another person or a third party to discuss your account details with Enbridge, you must contact our Enbridge Call Centre at 1-877-362-7434 to advise us of your permission to discuss your account with these parties.

In a landlord tenant situation Enbridge will follow directions recorded on the account.

## 6.10. Our Customer Service Process

**Step 1: Call the Enbridge Call Centre at 1-877-362-7434**
Enbridge customer service representatives (CSRs) are trained to help answer your questions.

**Step 2: Ask to Speak to a Supervisor**
If you feel that your questions are not being fully addressed by the CSR, please ask to speak to a supervisor. They'll try to work with you to resolve your issue.

**Step 3: Contact the Enbridge Customer Ombud**
If you've spoken to a CSR and a supervisor and are not completely satisfied with the solution provided, the supervisor will offer to elevate your concern to the Enbridge Customer Ombud's office.

For complete information regarding our dispute resolution process, please visit the Enbridge website: https://www.enbridgegas.com/contact-us/

# APPENDIX A

## DEFINITION OF TERMS

**British thermal unit** – means the amount of heat required to raise the temperature of one pound of distilled water from 60° Fahrenheit to 61° Fahrenheit.

**Building piping** – includes pipe, whether indoors, outdoors, exposed or buried, which brings gas from the "point of delivery" to each point of utilization including plugged or capped gas valves.

**Cubic metre** - A standard cubic metre of gas is the volume of gas contained in a one cubic metre at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa"). $10^3m^3$ equals 1,000 cubic metres.

**Curtailment** - An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

**Customer** – means any person, persons, company or corporation responsible for purchasing gas through Enbridge's meter.

**Gas** – natural gas or its equivalent containing not less than the heating value specified from time to time in Enbridge's rate schedules.

**Gas appliance** – means any device approved by the appropriate governmental authority which uses gas as a fuel or as a raw material.

**Joule** - A measurement of heat.

**Late payment effective date** – means the date late payment charges will be added to your bill if full payment has not been received.

**Late payment charge** – means a charge which is imposed when full payment of the gas bill is not made by the "late payment effective date".

**Meter** – means a device approved by the appropriate governmental authority and installed to measure the volume of gas delivered to the customer.

**Month or monthly** – means, for the purposes of calculating customers' accounts, a period of approximately 30 days.

**Point of delivery** – means that point at which gas leaves Enbridge's metering and regulating facilities and is delivered to you or, if there are no such facilities, Enbridge's shut-off valve.

**Property line** – means that line which delineates the boundary between one property and the next immediately adjacent property whether it is public or private.

**Rate schedule** – means one of a set of schedules filed by Enbridge with and approved by the Ontario Energy Board that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

**Service** – means the pipe or tubing and associated fittings which transmits gas from the pipeline to the meter inlet connection. Where unmetered gas is provided, the service shall be deemed to terminate at the shut-off valve located closest to the building entry, immediately inside the building wall. Where gas pressure regulation is necessary, the service regulator shall form part of the service.

**Standard conditions** – Temperature of 60°F and 15°C for Imperial and S.I. respectively. Pressure of 14.73 pounds per square inch absolute (psia) and 101.325 kilopascals absolute (kPa) for Imperial and SI respectively. Water vapour content less than 7 pounds per million cubic feet and 100 milligrams per cubic metre for Imperial and SI respectively.

# CHANGES TO THE SCHEDULE OF SERVICE CHARGES – "RIDER G"

1. In addition to gas distribution rates and rates charged for gas commodity provided by Enbridge, the Company maintains a list of charges, as Rider G to its Rate Handbook, that apply to specific customer initiated services provided. Since these are typically one-time services initiated by the customer, it is more appropriate to recover the costs associated with such services from those customers requiring them from time to time, as opposed to recovering these costs from all customers as a component of gas distribution rates. The revenues associated with these charges are discussed at Exhibit C1, Tab 5, Schedule 1.

2. Certain services are related to gas distribution field operations and are based upon an hourly charge-out rate, which in some cases also includes a material component. Fees for operations-related services were updated in 2009 based on approval from the Board in EB-2008-0219 (Exhibit C, Tab 1, Schedule 3). Other fees listed in Rider G pertain to customer care activities.

3. Enbridge has undertaken a review of its Schedule of Service Charges, Rider G. This review has indicated that Enbridge's current rates for these services are comparable with those of other Ontario service delivery organizations and utilities, and in most instances are lower. During the current Incentive Regulation period, the Company has realized efficiencies with the current field operations contract and increased productivity related to the implementation of EnVision in October 2004. As a result, the hourly rate for operations services will not increase.

4. Enbridge is proposing no changes to its customer care service fees as part of this rate application. Rather, Enbridge proposes that the fees remain at their current levels for 2012 and 2013.

5. Table 1 sets out Enbridge's proposed service charges for the 2013 Test Year.

Witnesses: S. McGill
M. Torriano

**Table 1**

**Proposed Rider G - Service Charges**

| Account Related Charges | Rate (excluding taxes) |
|---|---|
| **New Account Charge**<br>Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied. | $25.00 |
| **Appliance Activation Charge** (*for Commercial Customers Only*)<br>Charged to commercial customers for appliance activation on unlock and red unlock orders, except on the first unlock and service unlock at a premise. | $70.00<br>Minimum 1/2 hour work. Total amount depends on time required. |
| **Meter Unlock Charge** (*Seasonal or Pool Heater*)<br>Seasonal for all customer classes, or pool heater for residential only. | $70.00 |
| **Statement of Account** | |
| **Lawyer Letter Handling Charge**<br>Providing the customer's lawyer with gas bill information. | $15.00 |
| **Statement of Account Charge (for One-Year History)** | $10.00 |
| **Cheques Returned Non-Negotiable Charge** | |
| **Cheques Returned Non-Negotiable Charge** | $20.00 |

Witnesses: S. McGill
M. Torriano

| | |
|---|---|
| **Gas Termination** | |
| **Meter Lock re. non-payment "Red Lock Charge"**<br>Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by field collector). | $70.00 |
| **Removal of Meter**<br>Removal of a meter by construction and maintenance crew. | $280.00 |
| **Cut Off at Main Charge**<br>Cutting service off at main by construction and maintenance crew. | $1,300.00 |
| **Valve Lock Charge**<br>Shutting off service by closing the street shut-off valve. | |
| - Work performed by field investigator. | $135.00 |
| - Work performed by construction and maintenance personnel. | $280.00 |
| **Safety Inspection** | |
| **Inspection Charge**<br>For inspection of gas appliances; the Company provides only **one** inspection free of charge, upon the first time gas is introduced to a premise. | $70.00 |
| **Inspection Reject Charge (Safety Inspection)**<br>Energy Board Inspection rejects billed to the meter installer or homeowner. | $70.00 |
| **Meter Test** | |
| **Meter Test Charge**<br>Where a customer disputes meter reading(s), the customer may request to have the meter tested. This charge applies if the test confirms that the meter is recording consumption correctly. | |
| - Residential meters | $105.00 |
| - Non-residential meters | Time and material per contractor |

Witnesses: S. McGill
M. Torriano

| | |
|---|---|
| **Street Service Alteration** | |
| **Street Service Alteration Charge**<br>For installation of service line beyond allowable guidelines (for new residential services only). | $32.00 / metre |
| **NGV Rental** | |
| **NGV Rental Cylinder (Weighted Average)** | $12.00 / month |
| **Other Customer Services (Ad-hoc request)** | |
| **Labour Hourly Charge-Out Rate** | $140.00 |
| **Cut Off at Main Charge** (*Commercial and Special Requests*)<br>applicable to commercial services and other residential services that involve significantly more work than the average will be custom quoted. | Custom quoted |
| **Cut Off at Main Charge** (*Other Customer Requests*)<br>Other residential requests due to demolitions, fires, inactive services will be charged at the standard COAM rate. | $1,300.00 |
| **Meter In-Out** (*Residential Only*)<br>Relocating the meter from inside to outside per customer request. | $280.00 |
| **Request for Service Call Information**<br>Provide written information of the result of a service call as requested by home owners. | $30.00 |
| **Temporary Meter Removal**<br>At the customer's request. | $280.00 |
| **Damaged Meter Charge** | $380.00 |

CURRICULUM VITAE OF
TUNDE ADESIPO

Experience: Enbridge Gas Distribution Inc.

Manager, IT Business Support
2010

Manager, Internal Controls
2010

Senior Leader, Governance & Internal Controls
2007

Deloitte & Touche LLP

Senior Accountant
2005

UNIC Insurance Plc

Executive Director Finance & Administration
2001

PricewaterhouseCoopers LLP

Audit Manager
1998

Senior Auditor
1993

Education: Masters of Business Administration (Banking & Finance)
Certified Public Accountant (US CPA)
Associate Chartered Accountant (ACA)
Certified Information Systems Auditor (CISA)

Memberships: Information Systems Audit and Control Association (ISACA)

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
FAHEEM AHMAD

Experience: Enbridge Gas Distribution Inc.

Manager, Customer Portfolio and Policy
2010

Program Manager, Financial Assessment
2007

Supervisor, Gas Supply Analysis
2006

Program Manger, Portfolio Management
2004

Program Manager, Capital Appropriations
2003

Senior Advisor, Financial Business Performance
2001

Enbridge Incorporated

Financial Analyst, Business and Financial Analysis
2000

Lahore Electricity Supply Company

Manager, Operations
1996

Education: Certified Management Accountant (CMA)
Society of Management Accountants, 2004

Master of Business Administration
Wilfred Laurier University, 1999

Master of Science, Electrical Engineering
University of Engineering and Technology, Lahore, Pakistan, 1992

Memberships: The Society of Management Accountants of Ontario
Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2010-0146
RP-2002-0133

CURRICULUM VITAE OF
WILL AKKERMANS

Experience: Enbridge Gas Distribution Inc.

Director, System Operations – Operations Senior VP
2011

General Manager Ottawa – Operations Leadership
2007-2010

Director, Customer Care RFP Project – Customer, Reg. & Public Affairs
2006

General Manager Central Region
2003-2004

Manager Trans Serv/Gas Supp Operations
2000

Manager Special Projects
1999

Manager Supply Management Services
1996-1998

Supervisor Gas Control
1994-1996

Supervisor Pipeline
1993-1994

Pipeline Inspector
1992

Enbridge Inc.

Director, Business Technology
2006

Director, Asset Technology Management
2005-2006

Manager International Business Development
2000-2003

Education: Master of Business Admin, 1999

Bachelor of Science – Civil Engineering, 1993

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
RP-1999-0001

CURRICULUM VITAE OF
JIM ALTON

Experience:

Enbridge Gas Distribution Inc.

General Manager, Toronto Region
2010

Directory, Safety & Reliability
2010

General Manager, Central Region West
2008

Group Manager – Work Management Centre
2006

Manager, Operations Solutions
2006

Manager, Field Force Transformation
2004

Manager, Eastern Region Operations
2001

Manager, Engineering Maintenance
1999

CSA International

Project Manager, Oil & Gas Standards
1998

SENES Consultants Limited

Associate and Senior Environmental Engineer
1990

Consumers Gas Company Ltd

Assistant Manager, Gas Supply
1987

Project Engineer, LNG Project
1985

Manager, Operations Information Systems
1983

Distribution Planning Engineer
1980

TransCanada Pipelines

Jr. Engineering Assistant
1977

Education: B.A. Sc., Chemical Engineering
University of Toronto, 1980

Economics and Fundamental Accounting courses
York University, 1982

LNG Plant Operations Course
Institute of Gas Technology, 1985

Microprocessor Based Programmable, Controllers
University of Toronto, 1986

Canadian Securities Course
Investment Dealers Association, 1987

Compliance with Environmental Legislation
University of Toronto, 1990

Queens Executive Management Program
Queens University, 2003

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
EB-1985-LNG

CURRICULUM VITAE OF
LINDA AU

Experience: Enbridge Gas Distribution Inc.

Capital Budget Manager
2007

Capital Budget Supervisor
1995

Revenue and Gas Cost Analyst
1991

Canada Post Corporation

Operations Planning and Budget Officer
1990

Financial Analyst
1988

Queen Elizabeth Hospital

Senior Accountant
1986

Education: Certified General Accountant
CGA Ontario 1991

Bachelor of Business Management
Ryerson 1986

Appearances: (Ontario Energy Board)
EB-2011-0008
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2006-0034
RP-2005-0001

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2011-0226
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497
EBO 179-14/15

CURRICULUM VITAE OF
JOHN S. BRIGGS

Experience: Enbridge Gas Distribution Inc.

Manager, Asset Management Services
2011

Manager, Engineering Budgets
2008

Manager, Operations Budgets & Administration
2005

Manager, Capital Knowledge Centre
2002

Team Lead, Oracle EFS FA, PA, OPA
2001

GT Group Telecom

Manager, Capital Assets
2000

A.G. Simpson Automotive Inc.

Manager, Capital Appropriations & Expenditures
1998

Manager, Financial Reporting
1994

Alcan Aluminium Ltd.

Manager, Accounts Receivable
1988

Education: Bachelor of Arts
Victoria College University of Toronto, 1985

Appearances: (Ontario Energy Board)
EB-2005-0001
RP-2003-0203
RP-2002-0133

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Manager, Margin Accounting, and Gas Analytics
2011

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education: Certified Management Accountant,
The Society of Management Accountants of Canada, 2006

Ph.D. in Economics
Queen's University, 1998

Master of Arts in Economics
Queen's University, 1993

Bachelor of Arts (Honours) in Economics
University of Western Ontario, 1991

Memberships: Toronto Association for Business & Economics
The Society of Management Accountants of Canada

Appearances: (Ontario Energy Board)
EB-2011-0008
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2002-0133

CURRICULUM VITAE OF
EDITH CHIN

Experience: Enbridge Gas Distribution Inc.

Manager Upstream Strategy & Major Projects, Regulatory Affairs
2010

Manager Distributed Energy, Opportunity Development
2002

Manager Operations Services, Business Process Solutions
2002

Manager Supply Chain Process / Systems Development
Finance & Administration
2000

Enbridge Commercial Services
Senior Manager Supply Chain
2001

Independent Consultant
SAP Materials Management and other Warehouse Management systems
1999

Consumers Packaging Inc.
Energy and Materials Procurement, Product Management
1989

Domtar Chemicals
Product Management
Mergers and Acquisitions
Market Research & Planning
1982

3M Canada Inc.
Process Engineering
Quality Assurance
1978

Education: Hons. B. Sc. University of Western Ontario, London, Canada
M. Sc. University of Waterloo, Waterloo, Canada
Research Student, London School of Economics, London, England

Appearances: (Ontario Energy Board)
EB-2006-0305

CURRICULUM VITAE OF
LLOYD A. CHIOTTI

Experience: Enbridge Gas Distribution Inc.

Director, Distribution Asset Management
2010

Director, Asset Management Strategy
2006

General Manager, Envision Program
2003

General Manager, Central Region
2002

Director, Business Optimization
2001

Director, Operations Services
1999

Director, Business Transformation
1998

Regional General Manager, Central Region
(incl. Metro, Eastern, Western & Northern Zones)
1997

Regional General Manager, Metro Region
1992

Regional General Manager, Western Region
1989

Director, Information Services
1987

Manager, Systems Development
1984

Project Manager, Systems & Planning Dept.
1979

Datacrown

Data Processing Consultant
1977

Sears Canada Ltd.

Manager of Programming Services
1971

Education: Bachelor of Applied Science, Electrical Engineering
University of Toronto

Masters of Business Administration
University of Toronto

Memberships: CGA – Chair, Asset Management Task Force
IGU – Member Working Committee 4 - Distribution

Appearances: (Ontario Energy Board)
RP-2003-0203
RP-2002-0133
RP-2001-0032
RP-1999-0001
EBO 179-14/EBGO 179-15
EBA 795

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l’énergie/Régie du gaz naturel)
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

Education: CMA (3rd level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2011-0226
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0104/EB-2008-0408
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
TANYA M. FERGUSON

Experience: Enbridge Gas Distribution Inc.

Manager Customer Care Operations, Customer Care
2010

Manager Customer Care Financial Administration, Customer Care
2006

Manager Special Projects, Customer Care
2005

Senior Analyst, Planning and Projects
2002

Supervisor, Internal Reporting
2000

Enbridge Services Inc.

Financial Analyst, Financial Reporting
1999

Enbridge Gas Distribution Inc.

Corporate Accountant, Financial Reporting
1998

Audit Assistant, Audit Services
1998

Accounting Trainee, Financial Reporting
1997

Education: Masters of Business Administration
York University, 2002

Certified Management Accountant
Society of Management Accountants, 2000

Bachelor of Commerce (Honours)
University of Windsor, 1996

Memberships: Certified Management Accountant
Society of Management Accountants

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2010-0146
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
WILLIAM JEFFERY HOLDEN

Experience:

Enbridge Gas Distribution Inc.

Manager, Quality Acceptance / Risk
May 2011

Aird & Berlis, LLP

Law Clerk/Investigator
2007

Outerbridge Miller Sefton, LLP

Law Clerk/Investigator
2002

WJH Consulting

Paralegal
1998

McCague Wires Peacock Borlack McInnis & Lloyd

Law Clerk/Investigator
1994

Smith Lyons Torrance Stevenson & Mayer

Law Clerk/Investigator
1985

Lilly McCague Bowman

Law Clerk
1983

Education: BA/82, Carleton University

Memberships: Risk and Insurance Management Society

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
NARISA JOTIBAN

Experience: Enbridge Gas Distribution Inc.

Senior Market Analyst, Economic & Market Analysis
2008

Market Analyst, Economic & Market Analysis
2004

Education: Master of Arts, Economics
University of Waterloo, 2003

Bachelor of Science (Honours), Joint major in Economics and Environmental Science
Trent University, 2002

Memberships: Canadian Association for Business Economics - Toronto Chapter

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
JOHN JOZSA

Experience: Enbridge Gas Distribution Inc.

Assistant Controller
2007

Manager, Tax Services
2001

University of Toronto at Scarborough

Lecturer, Division of Management (part-time)
1999-2009

KPMG, Chartered Accountants

Senior Tax Manager
1997

Revenue Canada, Taxation

Corporate Tax Auditor
1993

Ernst & Young, Chartered Accountants

Senior Staff Accountant
1989

Education: CICA In-Depth Tax Course, 1999

Chartered Accountant, 1991

Honours Bachelor of Commerce Degree (Accounting)
Laurentian University, 1989

Memberships: Institute of Chartered Accountants of Ontario

Appearances: (Ontario Energy Board)
EB- 2006-0034
RP -2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

Education: Bachelor of Applied Science (Civil Engineering)
University of Waterloo, 1996

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0106
EB-2008-0219
EB-2007-0615
EB-2007-0724
EB-2006-0034
EB-2005-0551
EB-2005-0001

(RÉGIE DE L'ÉNERGIE)
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006
R-3587-2006
R-3537-2004

CURRICULUM VITAE OF
SAGAR KANCHARLA

Experience:

Enbridge Gas Distribution Inc.

Director, Business Performance
2011

Director, Strategy, Research & Planning
2008

Manager, Planning & Economics
2007

Manager, Financial and Economic Assessment
2005

Manager, Financial Assessment
2003

Senior Advisor, Financial Assessment
2002

Enbridge Inc.

Financial Analyst, Business & Financial Analysis
2000

GE Silicones India Pvt. Ltd., India

Manager – Market Development
1996

Ciba Specialty Chemicals Ltd., India

Product Manager – Pigments Division
1994

Marketing Executive – Polymers Division
1992

Education:

Masters of Business Administration
McMaster University, 2000

Post Graduate Diploma in Management
Indian Institute of Management, Ahmedabad, India, 1992

Bachelor of Engineering (Civil Engineering)
Andhra University, Visakhapatnam, India, 1990

Membership: Society of Utility and Regulatory Financial Analysts

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2007-0615
EB-2006-0066
EB-2006-0034
EB-2005-0539
EB-2005-0001
RP-2004-0015
RP-2003-0203

CURRICULUM VITAE OF
D. A. KELLY

Experience: Enbridge Gas Distribution Inc.

Manager, Capital Effectiveness
2011

Manager, Capital Budgets and Accounting
2007

Manager, Operational and Capital Budgets
2005

Manager, Cost Awareness and Analysis
2001

Senior Analyst, Operation and Maintenance
2000

Supervisor, Management Reporting
1997

Supervisor, Corporate Reporting
1992

Analyst, Financial Reporting
1991

Supervisor, Non-Utility Accounting
1989

Financial Statements Accountant
1988

Internal Audit Assistant
1987

Accounting Trainee
1985

Another Company

Corporate Loans, Guaranty Trust
1983

General Accounting, Consumers Glass
1981

Education: Bachelor of Business Management
Ryerson University, 1985

Certified Management Accountant
Society of Management Accountants, 1987

Memberships: Society of Management Accountants of Ontario

Appearances: (Ontario Energy Board)
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2002-0133
RP-2001-0032

CURRICULUM VITAE OF
LORRAINE KENNEDY

Experience: Enbridge Gas Distribution Inc.

Manager, Budgets and Scorecard
2008

Supervisor, Business Support
2005

Sr. Analyst, Budget & Financial Reporting
2001

Analyst, Opportunity Development
1999

Balance Sheet Clerk, Finance
1997

Intermediate Bank Reconciliation Clerk, Finance
1992

Accounts Payable Clerk, Finance
1991

Education: Queens Leadership Program
2010

Dale Carnegie Training - Presentation Skills
2010

Facilitation First – Internal Consulting Workshop
2010

Centennial College C.I.
Business Administration – General Management Diploma
1983

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
MATTHEW KIRK

Experience: Enbridge Gas Distribution Inc.

Manager, Cost Allocation
2012

Senior Rate Design Analyst, Regulatory Affairs
2010

Rate Design Analyst, Regulatory Affairs
2009

Market Analyst, Economic and Market Analysis
2006

Education: Master of Arts (Economics)
Wilfrid Laurier University, 2006

Bachelor of Arts (Honours Economics)
McMaster University, 2005

Memberships: Canadian Association of Business Economists (CABE)

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
VIVIAN G. KRAUCHEK

Experience:

Enbridge Gas Distribution Inc.

Manager, Gas Supply and Asset Optimization
2005

Enbridge Gas Services

Coordinator, Asset Optimization
2004

Supervisor, Operations
2003

Coordinator, Operations
2002

Dynegy Canada

Gas Scheduler/Operations
2000

Altra Energy Technologies, Inc

(Energy Transaction Management Software/On-line Trading Systems)
Sales Coordinator
1999

Education:

Masters of Sociology (with distinction)
University of Calgary, 1999

Bachelors of Sociology (High Honours)
University of Saskatchewan, 1994

Appearances:

(Ontario Energy Board)
EB-2010-0231
EB-2007-0932
EB-2006-0034

# CURRICULUM VITAE OF
# KERRY LAKATOS-HAYWARD

Experience:

Enbridge Gas Distribution

Director, Customer Care
2010

Director, Operations Services
2008

Director, Business Development & Strategy
2006

Manager, Business Development & Strategy
2003

Manager, Volumetric & Market Analysis
2000

Manager, Multi-Family Marketing
1997

Senior Economist, Economic Studies
1995

Ontario Hydro

End Use Economist, Load Forecasts
1994

Evaluation Analyst, Planning & Evaluation
1992

Education:

Bachelor of Arts (Specialist in Economics)
University of Toronto, 1990

Master of Science in Planning (Environmental Planning)
University of Toronto, 1992

Queen's Executive Program, 2005

Certificate in Carbon Finance, 2008

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040

CURRICULUM VITAE OF
DOUGLAS F. LAPP

Experience: Enbridge Gas Distribution Inc.

Chief Engineer
2011

Director, Engineering & Construction
2010

Chief Safety Officer
2006

Manager, Chief Operations & Logistics Engineer
2003

General Manager, Niagara Region
2002

Manager, Operations & Engineering Ozz Energy Project
2001

Manager, Distribution Planning
1999

Manager, Year 2000 Business Continuity Planning
1998

Manager, Distribution Operations, Northern Region
1995

Manager, System Regulation
1994

Manager, Engineering Projects
1991

Manager, Planning & Technical Services, Niagara Region
1990

Supervisor, Maintenance, Metro Toronto Region
1989

Senior Distribution Engineer, Congas Engineering Canada Ltd.
1988

Senior Engineer, Operations Engineering
1987

Project Engineer, Eastern Region
1985

Operations Engineer, Operations Engineering
1982

Education: Queens Executive Program, 1998

University of Toronto
Master of Engineering in Welding, 1990

University of Waterloo
Bachelor of Applied Science in Civil Engineering, 1982

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2007-0615
EB-2006-0034
RP-2005-0001
RP-2003-0203
RP-2002-0133
RP-2000-0040
RP-1999-0001
EBRO 495
EBRO 487/ EBRO 485
EBLO 241
EBLO 256/EBA 737/EBC 246
EBLO 261/EBA 785/EBC 266
EBA 795

CURRICULUM VITAE OF
LISA L. LAWLER

Experience: Enbridge Gas Distribution Inc.

Director, Integrity
2010

Chief Engineer
2008

Manager, Enbridge Ontario Wind Power Project
2006

Manager, Strategic Distribution Alliance
2004

Manager, Distribution Planning
2001

Manager, Operations Eastern Region
1999

Manager, Distribution Expansion
1997

General Supervisor, Maintenance (West)
1996

Supervisor, Construction & Maintenance Administration
1995

Operations Engineer
1991

Congas Engineering Canada Limited
(a former subsidiary of The Consumers' Gas Company Ltd.)
International Marketing Engineer
1989

Education: Master of Business Administration
Wilfrid Laurier University, 1989

Bachelor of Applied Science, Chemical Engineering, Honours Program
University of Waterloo, 1988

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
RP-2002-0133

CURRICULUM VITAE OF
RAYMOND LEI

Experience:

Enbridge Gas Distribution Inc.

Manager, Budgets and Business Support
2010

Manager, Corporate Budgets and Analysis
2007

Manager, Financial Analysis
2007

Senior Analyst, Planning and Projects
2005

Rogers Wireless Inc.

Senior Analyst, Budgets and Forecast
2001

Royal LePage Relocation Services Ltd.

Financial Analyst
2000

Kodak (China) Limited

Business Analyst
1995

Education:

Certified General Accountant
Certified General Accountants of Ontario, 2005

Master of Business Administration
York University, 2000

Bachelor of Arts in Commerce and Economics
Sichuan University, China

Memberships: Certified General Accountant, Ontario

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172

CURRICULUM VITAE OF
MICHAEL LISTER

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Policy & Strategy
2010

Manager, Investment Planning
2006

Manager, Volumetric & Market Analysis
2004

Supervisor, Volumetric & Market Analysis
2003

Sr. Market Analyst, Volumetric & Market Analysis
2002 - 2003

NRI Industries Inc.

Production Scheduler, Logistics
1999-2000

Fairlee Fruit Juices Ltd.

Raw Materials Coordinator
1998

Coats Canada Inc.

Production Planner, Materials & Logistics
1996-1997

Education: Chartered Financial Analyst
CFA Institute, 2005

Master of Business Administration
York University, 2002

Bachelor of Commerce
St. Mary's University, 1996

Memberships: CFA Institute
Toronto CFA Society

Appearances: (Ontario Energy Board)
EB-2010-0060
EB-2009-0172
EB-2009-0084
EB-2007-0615
EB-2005-0001
RP-2003-0203

(New York Public Service Commission)
05-G-1635

(New York Public Service Commission)
08-G-1392

CURRICULUM VITAE OF
TREVOR MACLEAN

Experience:

Enbridge Gas Distribution Inc.

Director, Business & Market Development
2008

Enbridge Gas New Brunswick

Manager, Distribution Operations
2006

Manager, Sales & Marketing
2004

RLG International

Consultant
2000

825929 Alberta Ltd

Consultant
1997

ISM (IBM Global Services)

Director, Systems Integration
1995

Manager Operations, Systems Integration
1994

National Defence/Canadian Forces

Military Officer
1986

Education:

Master of Business Administration
Queen's University, 1995

Bachelor of Arts (Special)
University of Alberta, 1986

Appearances:

(Ontario Energy Board)
None

CURRICULUM VITAE OF
NEIL MacNEIL, P.Eng.

Experience: Enbridge Gas Distribution Inc.

Manager, Engineering Major Projects
2011

Sr. Engineering Project Manager
2010

Engineering Project Manager
2007

Construction Supervisor
2006

Sr. Engineering Project Leader
2005

Engineering Project Leader
2003

Education: BSc Chemical Engineering Degree, 2003

Memberships: Professional Engineers Ontario
Technical Standards and Safety Authority

Appearances: (Ontario Energy Board)
EB-2008-0065

CURRICULUM VITAE OF
ANDREW MANDYAM

Experience: Enbridge Gas Distribution Inc.

Manager, Marketing and Energy Efficiency
2011

Manager, Demand Side Management and Portfolio
2010

Customer Information System Replacement Project Business Manager
2007 - 2009

Manager, Customer Care and Customer Information System Program Operations
2006

Manager, Information Technology Solutions and Support
2005

Senior Project Manager, Information Technology Solutions and Support
2003

Oracle Corporation

Practice Manager
1997 – 2003

Compaq Canada

Program Manager
1995 – 1997

Ontario Hydro

Associate Engineer
1990 - 1995

Education: B.A.Sc. Mechanical Engineering
University of Toronto
1990

Memberships: Professional Engineers of Ontario
Project Management Institute

Appearances: (Ontario Energy Board)
EB-2011-0295
EB-2011-0277
EB-2010-0146
EB-2010-0175
EB-2010-0029
EB-2009-0172
EB-2006-0034

CURRICULUM VITAE OF
BRUCE MANWARING

Experience: Enbridge Gas Distribution Inc.

Manager Contract Compliance - Direct Purchase
2006

Account Executive - Commercial Markets
2006

Energy Management Consultant
1999

Marketing National Accounts
1997

Natural Gas Vehicles
1993

Education: Marketing Administration Diploma, Seneca College
Chartered Industrial Gas Consultant

Appearances: (Ontario Energy Board)
EB-2008-0106

CURRICULUM VITAE OF
STEVE MCGILL

Experience: Enbridge Gas Distribution Inc.

Manager, Billing & Customer Systems
2005

Manager, Strategic Projects & Market Analysis
2003

Manager, Customer Support & Advocacy
2000

Manager, Customer Accounting Projects
1995

Manager, Large Volume Billing
1992

Manager, Industrial Sales, Metropolitan Toronto
1990

Manager, Rate & Contract Administration
1987

Rate Research Analyst
1985

Market Analyst
1981

Distribution Planner
1979

TransCanada Pipelines Limited

Junior Statistician

Junior Draftsman

Education: Bachelor of Arts (Honours Geography), University of Toronto, 1978

Miscellaneous short courses in Public Utility Management,
General Management, and Accounting

Other: Member of the Board of Directors and Treasurer of the Oshawa Ski Club

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2011-0226
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0058
RP-1999-0001
EBRO 497-01
EBRO 497
EBRO 495
EBRO 492
EBRO 490
EBRO 487
EBO 179-14/15

CURRICULUM VITAE OF
CHRIS MEYER

Experience: Enbridge Gas Distribution Inc.

Manager, External Communications
2011

Manager, Executive Communication Support
2008

Senior Communication Advisor
2001

Education: Strategic Communication Management Certificate
(Ithaca College), 2008

Bachelor of Applied Arts, Journalism
(Ryerson), 1990

Memberships: International Association of Business Communicators (Accredited)

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
BIJU MISRA

Experience: Enbridge Gas Distribution Inc.

Project Manager, Information Technology,
2006

Sr. Project Manager, Information Technology,
2007

IT Solution & Support Manager, Information Technology,
2008

Manager Business Applications,
2009

Education: Bachelor of Science, Electrical Engineering. Kansas State University
Certificate, Business Management Fundamentals. University of Toronto

Memberships: Project Management Institute (PMI)

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
DONALD RITCHIE (RITCH) MURRAY, P Eng

Experience: Enbridge Gas Distribution Inc

Project Manager, Engineering Major Works
2009

Project Manager, Engineering Standards and Technical Services
2008

Program Manager, Asset Management
2006

Field Manager, Quality Acceptance
2003

Engineering Project Leader
2000

Enbridge Gas New Brunswick Inc

Manager, Planning and Technical Services
2004

Education: Master of Business Administration
Ryerson University, 2008

Bachelor of Engineering (Mechanical)
Dalhousie University, 2000

Bachelor of Science (Biology)
Acadia University, 1994

Memberships: Professional Engineers of Ontario
Professional Engineers and Geoscientists of New Brunswick

Appearances: (New Brunswick Energy and Utilities Board)
Petitcodiac River Crossing Project, Leave to Construct Hearing, 2006

# CURRICULUM VITAE OF STUART MURRAY

Experience:

Enbridge Gas Distribution Inc.

Manager, Investment Review and Economic Analysis
2011

Manager, Investment Review and Customer Growth
2008

Manager, Financial Assessment
2006

Pitney Bowes Canada

Project Manager, Enterprise Program Office
2003

Finance Manager, Service Operations
2001

Finance Manager, New Business Development
2000

Canadian Tire Corporation

Business Analyst, Marketing Finance
1997

Financial Analyst, Corporate Planning
1996

Education:

Master of Business Administration
McMaster University, 1995

B.A. Economics, Administrative & Commercial Studies
University of Western Ontario – 1993

Appearances:

(Ontario Energy Board)
EB-2006-0034

CURRICULUM VITAE OF
STEPHEN POGORSKI Ph.D.,P.Eng.

Experience: Enbridge Gas Distribution Inc.

Manager, Asset Risk Management
2011

Manager, Business Development Turboexpander
2009

Manager, Market Development
2005

Ask Information Technologies Inc.

President
1996

The Consumers Gas Company Limited

Manager, Supply Management Services and Special Projects
1994

Manager, Gas Supply Studies
1993

British Gas Holdings Inc.

Senior Financial Analyst
1991

Chemical Projects Ltd.

Manager, Research and Development
1986

Education: Professional Engineer Ontario (Ph.D., P.Eng.)

Memberships: Professional Engineers Ontario

Appearances: (Ontario Energy Board)
EBRO 492

CURRICULUM VITAE OF
SANDEE QIAN

Experience: Enbridge Gas Distribution Inc.

Manager Margin Budgets & Analysis, Finance
2010

Manager Financial Analysis, Corporate Budgets & Analysis
2008

Program Manager Capital Appropriation & Scorecard, Finance
2006

Senior Financial Analyst, Financial Assessment
2006

Financial Analyst, Financial Assessment
2004

Motorola (China) Electronics Ltd.

Senior Analyst
1995

Education: Certified Management Accountant (CMA), 2007

Master of Business Administration
York University, 2003

Bachelor of Engineering
Northwestern Polytechnic University, China

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
None

# CURRICULUM VITAE OF
# BARRY REMINGTON

Experience: Enbridge Gas Distribution Inc.

Manager, Property Taxes, Land Services Department
1990

Bell Canada

Manager, Property Valuation, Property Tax Department
1978

Marathon Realty Company Limited

Property Tax Representative
1976

Ministry of Revenue – Assessment Division

Property Assessor
1973

Memberships: Canadian Property Tax Association, Inc. (CPTA)
(Past President of CPTA in 1996)
Institute of Municipal Assessors
Institute for Professionals in Taxation (IPT)

Committee: CPTA Board of Directors – National Treasurer
CPTA Past Presidents Committee
IPT Canadian Liaison Committee

Education: Assessment Administration Diploma
Loyalist College, 1973

Appearances: (Ontario Energy Board)
EB-2006-0034

Assessment Review Board (ARB)
Assessment Appeal Tribunal for Property Assessment and Taxation

CURRICULUM VITAE OF
JIM SANDERS, P.Eng.

Experience: Enbridge Gas Distribution

Director, Storage Operations
2008

Manager, Strategic Distribution Alliances
2006

Duke Energy Gas Transmission
Manager, Major Projects
2005

Union Gas Limited
Manager of Operations Support
2003

Manager Operation Engineering
2000

Manager of Business Development
1999

Manager of Operations and Construction
1993

Planning and Project Engineer
1989

Nuclear Activation Services Ltd.
Manager of Operations
1986

Education: McMaster University
Masters of Engineering and Public Policy (candidate)
2010-2011

University of Waterloo
Bachelor of Applied Science, Civil Engineering
1981-1986

Memberships: Professional Engineers of Ontario, 1988, 40537201

Appearances: (Ontario Energy Board)
RP-2003-0063
E.B.A. 691
E.B.A. 691
E.B.C. 206,
E.B.A. 670
E.B.A. 700-708
E.B.C. 233-255
E.B.L.O. 253
E.B.C. 213
E.B.A. 687

CURRICULUM VITAE OF
JODY L. SARNOVSKY

Experience: Enbridge Gas Distribution Inc.

Director, Energy Supply & Policy
2011

Manager, Gas Storage Development
2010

Manager, Distribution Planning
2007

Manager, Strategic & Key Accounts
2004

Manager, Customer Support
2001

Manager, Transactional Services
1999

Manager, Transactional Services Sales
1997

Supervisor, Gas Supply Regulatory Projects
1995

Regulatory Analyst
1991

Education: Master of Business Administration
McMaster University, 1990

Bachelor of Commerce (Honours)
McMaster University, 1989

Appearances: (Ontario Energy Board)
EB-2005-0551
EB-2005-0001
RP-2003-0203
RP-2002-0133
RP-2000-0040
EBRO 497
EBRO 495

CURRICULUM VITAE OF
HULYA SAYYAN

Experience: Enbridge Gas Distribution Inc.

Advisor, Economic & Market Analysis
2011

Senior Market Analyst
2007

Risk Software Technologies

Economic Specialist
2005

Marmara University

Assistant Professor, Econometrics Department
2002

Instructor, Econometrics Department
2001

Research Assistant, Econometrics Department
1994

Education: Ph.D. in Econometrics
Marmara University, 2000

Master of Science in Statistics
Marmara University, 1995

Bachelor of Science in Statistics
Mimar Sinan University, 1992

Memberships: Toronto Association for Business & Economics (CABE)

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2010-0146

CURRICULUM VITAE OF
DONALD R. SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Gas Costs and Budget
2010

Manager, Gas Cost Knowledge Centre
2003

Manager, Gas Costs and Budget
1989

Co-ordinator, Gas Costs
1984

Financial Statement Accountant
1980

Chief Clerk, Financial Statements
1979

Advanced Accounting Trainee
1978

Education: Business Administration Diploma
Ryerson Polytechnical Institute, 1978

Appearances: (Ontario Energy Board)
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001

Appearances: (Ontario Energy Board) Con't
EBRO 497
EBRO 495
EBRO 492
EBRO 490
EBRO 487
EBRO 485
EBRO 479
EBRO 473
EBRO 465

CURRICULUM VITAE OF
RYAN SMALL

Experience: Enbridge Gas Distribution Inc.

Senior Analyst, Regulatory Accounting
2006

Analyst, Regulatory Accounting
2004

Supervisor, Gas Cost Reporting
2001

Senior O&M Clerk
2000

Bank Reconciliation Clerk
1999

Accounting Trainee
1998

Education: Certified Management Accountant,
The Society of Management Accountants of Ontario, 2003

Diploma in Accounting,
Wilfrid Laurier University, 1997

Bachelor of Arts in Economics
The University of Western Ontario, 1996

Appearances: (Ontario Energy Board)
EB-2011-0008

CURRICULUM VITAE OF
MANNY SOUSA

Experience: Enbridge Gas Distribution Inc.

Manager Community & Municipal Relations
2008

Manager Community Relations
2004

Manager Community and Event Services
1999

Manager, Appliance Centres
1998

Black Photo Corporation

Regional Sales Manager
1990

Store Manager
1981

Education: University of St. Michael's College at University of Toronto
Certificate in Corporate Social Responsibility

Boston College
Certificate in Corporate Community Involvement

Seneca College
Business Diploma

Memberships: Providence Healthcare Foundation
Advisory Board – Providence Community Partners

Scarborough Chamber of Commerce
Past Chair

Appearances: (Ontario Energy Board)
None

# CURRICULUM VITAE OF
# PATRICIA A. SQUIRES

Experience: Enbridge Gas Distribution

Director, Strategy, Research and Planning
2011

Manager, Operations PMO
2011

Manager, Market Development
2008

Manager Mass Markets and New Construction Market Development
2006

Manager, Energy Technology
2004

Manager, DSM and Program Evaluation
2001

Manager, Planning and Evaluation
1998

Senior Evaluation and Market Planning Analyst
1997

Conservation Analyst
1994

Economic Researcher
1991

Research Assistant
1990

Education: Master in Environmental Studies
York University, 1996

Bachelor of Applied Arts (Applied Geography)
Ryerson Polytechnic University, 1990

Certificate in Economic Analysis
Ryerson Polytechnic University, 1990

Appearances: (Ontario Energy Board)
EB-2010-0175
EB-2009-0172
EB-2009-0154
EB-2008-0150
EB-2006-0034
EB-2006-0021
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2000-0040
RP-1999-0001

(Régie du Gaz Naturel)
R-3355-96

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Economic & Market Analysis
2012

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

The Canadian Institute

Conference Producer
1997

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

Education: Master of Arts in Economics
University of Maine, 1995

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2008-0219
EB-2008-0106

(RÉGIE DE L'ÉNERGIE)
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008

CURRICULUM VITAE OF
MINA TORRIANO

Experience: Enbridge Gas Distribution Inc.

Manager, Business Support
2010

Manager, Operations Accounting
2006

Manager, Financial Asset Management
2005

Supervisor Asset Reporting and Analysis
2000

The Consumers Gas Company Ltd

Assistant Plant Accountant
1996

Systems Coordinator
1992

Plant Accounting Clerk
1987

Education: Accounting Degree – Humber College of Applied Arts & Technology

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
MICHAEL TREMAYNE

Experience: Enbridge Gas Distribution Inc.

Manager, NGV Department
2006

Manager Infrastructure & Marketing,
NGV Department
1993

Manager NGV Technology & Development,
Technology and Development Department
1989

Project Manager Residential / Commercial Technology,
Technology and Development Department
1986

Energy, Mines and Resources Canada, Ottawa

Project Manager, Energy Conservation Branch
1983

Scanada Consultants Limited, Ottawa

Technical Advisor
1982

Canada Mortgage and Housing Corp., Ottawa

Development Consultant, Technical Research Division
1980

Asecor Engineering Limited, Ottawa

Design Analyst
1980

Education: Bachelor of Engineering, Carleton University - Ottawa, Ontario

Memberships: Professional Engineer of Ontario

Appearances: (Ontario Energy Board)
EB-2005-0001

CURRICULUM VITAE OF
SHEILA TROZZI

Experience: Enbridge Gas Distribution Inc.

Manager Human Resources Business Support
2010

Human Resources Business Partner
2004

Human Resources Consultant
1998

Employee Relations Representative
1989

Human Resources Records Clerk
1980

Billing Clerk
1976

Education: Certified Human Resources Professional (CHRP 1993)

Memberships: Human Resources Professional Association

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
MARC N. WEIL

Experience: Enbridge Gas Distribution Inc.

Director, Human Resources & Facilities
2010

Director, Information Technology
2006

Manager, Application Support
2004

Enbridge Inc.

Supervisor, Corporate IT Operations
2001

Enbridge Pipelines Inc.

Senior Systems Analyst
2000

Systems Analyst III
2000

Systems Analyst II
1998

Systems Analyst I
1997

Education: Management Essentials – Mini MBA – Executive Education
University of Calgary, 2003

Bachelor of Commerce (Management Information Systems)
University of Alberta, 1997

Business Administration Diploma (Management)
Northern Alberta Institute of Technology, 1994

Memberships: Conference Board of Canada – Council of HR Executives
The Board of Trade of Metropolitan Toronto

Appearances: (Ontario Energy Board)
EB-2011-0008
EB-2010-0042
EB-2006-0034

CURRICULUM VITAE OF
HENRY WONG

Experience: Enbridge Gas Distribution Inc.

Director, Information Technology
2010

Manager of Business Applications
2006

Manager of Solution Delivery Group
2004

Manager of Applications Support
2001

Source Medical Corp.

Vice President & Chief Information Officer
1998

Imperial Oil Ltd.

Systems Manager, Distribution and Supply
1995

Distribution Systems Manager
1990

Texaco Canada Inc.

Senior Coordinator, Planning & Systems
1986

Coordinator, Computer Modelling
1982

Miracle Food Mart

Manager of Systems Development
1981

Shell Canada Ltd.

Systems Analyst
1979

Analyst Programmer
1978

| | |
|---|---|
| Education: | Master of Mathematics in Statistics<br>University of Waterloo, 1978 |
| | Bachelor of Mathematics<br>University of Waterloo, 1977 |
| Appearances: | (Ontario Energy Board)<br>EB-2006-0034 |

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience:

Enbridge Gas Distribution Inc.

Director, Finance & Control
2010

Enbridge Inc.

Senior Director, Chief Audit Executive
Audit Services & Internal Controls
2007

Director, Audit Services
1999

Safeway Inc./Canada Safeway Limited

Manager, Corporate Audit Services
1991

Deloitte & Touche

Audit Manager
1987

Education:

Certified Internal Auditor
Institute of Internal Auditors, 2003

Chartered Accountant
Canadian Institute of Chartered Accountants, 1986

Bachelor of Commerce-Accounting
University of Calgary, 1983

Memberships:

Canadian Institute of Chartered Accountants
Institute of Chartered Accountants of Alberta
Institute of Chartered Accountants of Ontario
Institute of Internal Auditors
Financial Executives International, Canada
Corporate Executive Board, Audit Directors and Risk Management Advisory Council
University of Calgary, Haskayne School of Business, Mentorship Program
Enbridge Inc. Mentorship Program

Appearances:

(Ontario Energy Board)
EB-2011-0277
EB-2011-0008

***Manuel Monteiro***

Manuel Monteiro is a Partner in the Retirement Risk & Finance business in Mercer's Toronto office. Manuel joined Mercer in 1999 after spending six years at two other major consulting firms.

Manuel advises clients on the design, funding, accounting, administration and governance of their pension arrangements. He has significant experience helping employers with pension and benefit issues in collective bargaining and in merger, acquisition and divestiture situations.

Manuel's clients include large and medium-sized organizations in the public sector and in the financial services, mining, entertainment and pharmaceutical industries. He also consults to a large university and is part of our team that was recently awarded a project to re-design the pension arrangements for the public sector in Trinidad & Tobago. In addition to his client responsibilities, Manuel is a former member of Mercer's professional group for our retirement consulting business in Canada. As well, Manuel is considered an internal expert on pension funding and risk management issues.

In addition to his work at Mercer, Manuel is a member of the Canadian Institute of Actuaries Pension Plan Financial Reporting Committee and served on the Canadian Institute of Actuaries Pension Vision Taskforce. He is also the Chair of the Actuarial Advisory Committee of the Financial Services Commission of Ontario.

Manuel has been a speaker at pension conferences organized by the Canadian Institute of Actuaries, the Association of Canadian Pension Management and Federated Press. He was also a regular lecturer for the Humber College Pension Plan Administration Certificate course.

Manuel graduated from the University of Waterloo on the Deans Honours List with a Bachelor of Mathematics (Actuarial Science) in 1993. He qualified as a Fellow of the Society of Actuaries and a Fellow of the Canadian Institute of Actuaries in 1995.

# CURRICULUM VITAE OF
# CHRIS BONIFACE

Experience:

Enbridge Inc.

Senior Manager Total Compensation
2010

Deloitte

National Director Total Rewards
2007

Senior Manager Compensation & Benefits
2005

Sears Canada

Manager Total Rewards
2002

Senior Analyst Total Rewards
2000

Canadian Imperial Bank of Commerce

Compensation Analyst
2000

Towers Perrin

Associate Consultant
1998

Education:

Honours Bachelor of Arts
University of Toronto

Master in Business Administration
Richard Ivey School of Business – University of Western Ontario

Certified Compensation Professional (CCP)

Certified Benefits Professional (CBP)

Global Remuneration Professional (GRP)

WorldatWork (formerly the ACA)

Memberships: WorldatWork

# CURRICULUM VITAE OF DARREN YAWORSKY

Experience:

Enbridge Inc.

Director, Treasury
2011

Senior Manager, Corporate Finance
2010

Manager, Treasury
2008

Bank of Montreal

Managing Director, BMO Capital Corporation
2007

Director, Corporate Finance
2004

Royal Bank of Canada

Senior Manager, Risk Management
2003

Manager, Global Energy Risk Management
2001

Assistant Manager, Western Canada Risk Management
2000

Senior Account Manager
1997

Education:

Doctor of Business Administration Candidate, 2012

Master of Business Administration, 2001

Certified Economic Developer Designation, 1996

Economic Development, 1996

Honours Bachelor of Commerce, 1994

Memberships: Economic Developers Association of Canada, 1996

Appearances: (Ontario Energy Board)
None

# CURRICULUM VITAE OF
# DR. REBECCA HONEYFIELD

Experience: Navigant Consulting Inc.

Associate Director, Energy (Fuels Group)
2011-Present

Managing Consultant, Energy (Fuels Group)
2008-2011

Senior Consultant, Energy (Fuels Group)
2006-2008

Education: Doctor of Philosophy (Applied Mathematics)
University of California, Davis, 2006

Bachelor of Science (Mathematics, Magna Cum Laude)
California State University, Sonoma 1999

Memberships: Global Association of Risk Professionals (GARP)

Projects: Current manager of Navigant's semi-annual North America long-term fundamental natural gas market outlook. Includes review of econometrically based sectoral natural gas demand curves.

Performed Monte Carlo analyses of California's Department of Water Resources annual revenue requirement to "stress" natural gas price forecasts.

Developed statistical models to quantify the dollar impact of alleged price manipulation in support of a litigation case for a confidential client in the US propane market, which also involved researching market volumes and pricing.

Performed various statistical analyses of natural gas storage, generation outage events, and planning variances for Tennessee Valley Authority.

For a confidential client, estimated the embedded option value in a natural gas contract where the buyer had a choice of markets. After developing the necessary forward price curves (based on regression models), volatility curves, and correlations, used energy derivatives software (FEA's @ENERGY) to estimate this option value as a spread option across multiple periods. Analysis included full chain economics for shipping, regasification, and pipeline transportation costs.

For Ph.D. dissertation, developed computer model to simulate blood flow and pressure in human arterial system to investigate the effect of the hardening of arteries on arterial fluid dynamics. Dissertation work involved extensive programming, quantitative analysis, problem-solving, and research design.

Power System Engineering, Inc.

# STEVEN A. FENRICK

## Leader, Benchmarking and Economic Studies

### SUMMARY OF EXPERIENCE AND EXPERTISE

- Leader of PSE's Economics and Market Research group which conducts research in the fields of DSM, performance benchmarking, incentive regulation, load research and forecasting, and survey design and implementation
- Manages PSE's cost, productivity, and reliability performance benchmarking practice
- Directs research on value-based reliability planning efforts for electric utilities
- Expert in performance-based ratemaking and incentive regulation
- Directs economic research on investigating the impacts and costs/benefits of DSM programs and designing statistically robust pilot designs

### PROFESSIONAL EXPERIENCE

#### Power System Engineering, Inc. – Madison, WI (2009 to present)

##### Leader, Economics and Market Research

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management, load research, load forecasting, end-use surveys, and market research.

- Leads research, on an annual basis, with over a dozen electric utilities in evaluating cost, productivity, and reliability performance and uncovering methods to improve their operations
- Benchmarking consultant to the Ontario Energy Board regarding their 3rd Generation Incentive Regulation Plan for the last two years
- In the process of designing and analyzing DSM pilot projects at over 25 electric utilities across the country
- Testimony experience regarding performance benchmarking and productivity analysis
- Has given several presentations on performance benchmarking and productivity analysis, costs and benefits of DSM programs, and measurement and verification (M&V) techniques.
- Key speaker at EUCI conferences regarding cost and reliability performance evaluation and productivity analysis of distribution utilities

#### Pacific Economics Group – Madison, WI (2001 - 2009)

##### Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling.

- Instructor at 2009 EUCI "Electric Utility Cost and Service Quality Benchmarking" conference.
- Developed a reliability benchmarking model for power distribution comparing utility performance.
- Managed and supervised PEG support staff in research and marketing efforts.

## EDUCATION

University of Wisconsin - Madison, WI
Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI
Master of Science, Agriculture and Applied Economics

### Publications & Papers

- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Thesis.

### Recent Presentations

- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.

- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

## History of Major Research Projects

1. Evaluation and review of business cases for reliability-driven projects, Toronto Hydro, 2012.
2. Energy efficiency rebate optimization, Corn Belt, 2012.
3. Energy efficiency and demand response customer baseline load algorithm development for an MDM system vendor, 2012.
4. Incentive Regulation Productivity and Benchmarking, Enbridge Gas Distribution, 2011/2012
5. Reliability Benchmarking and Target Setting, Vectren 2011/2012
6. DSM potential analysis, South Central Indiana, 2011/2012
7. Annual benchmarking updates of Ontario's 77 power distribution utilities, OEB 2011
8. Cost and reliability benchmarking research involving a group of 20 electric utilities, 2011
9. Energy Efficiency program design and cost effectiveness, Corn Belt 2011
10. Cost/Benefit model of direct load control, Corn Belt 2011
11. Peak time rebate demand response program design and cost effectiveness, Heartland 2011
12. Value Based Reliability Planning project at New Hampshire Electric Cooperative, 2010
13. DSM research on pilots at 25 electric utilities, 2010-2014
14. Benchmarking research involving a group of 14 electric utilities, 2010
15. M&V research of OPower energy efficiency program, 2010.
16. M&V research of Smart Thermostat demand response program, 2010.
17. Benchmarking research regarding Union Electric, 2010
18. Benchmarking research regarding the three Ameren Illinois Utilities, 2009
19. Benchmarking research for Central Vermont Public Service, 2009
20. Benchmarking research on Oklahoma Gas & Electric, 2009
21. Research North American power industry revenue forecast precedents, HECO, 2008.

22. Revenue Adjustment Mechanism for CVPS Revenue Decoupling Proposal, CVPS, 2008.
23. Productivity Research for Bundled Power Service, HECO, 2008.
24. A&G Power Benchmarking Research. 2008.
25. Productivity Research of Ontario's Power Distribution Utilities, OEB, 2008.
26. Productivity Research of U.S. Power Generation and Distribution, APS, 2007.
27. Productivity Research of Northeast Power Distribution, CMP, 2007.
28. Productivity Research of Ontario's Gas Distribution Utilities, OEB, 2007.
29. Benchmarking Research of Ontario's Power Distribution Utilities, OEB, 2007.
30. Benchmarking Research of Electric A&G Expenses, Michigan PSC, 2006.
31. Productivity Research for Gas Distribution, Sempra, 2006.
32. Productivity Research for Power Distribution, Sempra, 2006.
33. Benchmarking Research for Gas Distribution, Nstar Gas, 2006.
34. Benchmarking Research for Power Distribution, Central Vermont PSC, 2005.
35. Benchmarking Research of Nuclear Power Generation, Sempra, 2005.
36. Research on Rate Trends for Electric Power, EEI, 2005.
37. Benchmarking Research of Bundled Power Service, Florida Power, 2005.
38. Benchmarking Research of Canadian Electric Distribution, Hydro One, 2005.
39. Benchmarking Research of Gas Distribution, Bay State, 2005.
40. Benchmarking Research of Electric Distribution, Aquaelectra, 2004.
41. Benchmarking Research for the Caribbean Water Distribution Industry, Aquaelectra, 2004.
42. Compensatory Rate Trend for the U.S. Gas Industry, 2004.
43. Productivity Research for the U.S. Electrical industry, TXU, 2004.
44. Research on Productivity and Benchmarking for Queensland, Australia Electrical Companies, 2004.
45. Research on Productivity and Benchmarking for Gas and Electric Industries for Sempra, 2004.
46. Research on Productivity and Benchmarking for Jamaican Power Company. JPS, 2003-4.
47. Cost analysis research and benchmarking for the Bolivian Power regulator, 2003.

48. Research on Productivity and Benchmarking for a Canadian Power Transmission Company, 2002.
49. Research on Productivity and Benchmarking for a Natural Gas Distributor. Boston Gas, 2002-3.
50. Research on Benchmarking for Bundled Power Service. AmerenUE, 2002
51. Statistical Benchmarking for Electric Power Transmission. Transcend, 2002.
52. Statistical Benchmarking for three Australian Gas Utilities, 2001.
53. Power Distribution TFP trends for Bangor Hydro, 2001.

Power System Engineering, Inc.

# LULLIT GETACHEW, PhD
## SENIOR ECONOMIST

### SUMMARY OF EXPERIENCE AND EXPERTISE

- Expert in applying econometric methods to utility research topics.
- Provides econometric support and review on all PSE economic and market research practice areas.
- Conducts empirical studies using multiple programming languages.

### PROFESSIONAL EXPERIENCE

**Power System Engineering, Inc. – Madison, WI (2011-present)**

**Senior Economist**

Provides consulting services to electric utilities nationwide in load forecasting and research, performance benchmarking, customer and end-use surveys, market research, energy efficiency filings, and demand-side management.

**Pacific Economics Group Research – Madison, WI (2002-2011)**

**Senior Economist**

Conducted research in support of regulatory filings of energy utilities. Analyzed efficiency of regulated entities using various econometric and non-parametric methods including panel data, frontier methods, and system estimators. Prepared studies and reports for performance-based regulation of transmission and distribution energy businesses, undertook total and operation cost benchmarking, prepared reports for rate settlements, and marketed flexibility in rate designs. Undertook studies on service quality conditions and requirements in regulation.

**Rice University Economics Department – Houston, TX (1999-2002)**

**Research Assistant to Professor Robin Sickles (Summer 1999-Summer 2002)**

Performed a time-series analysis of aircraft demand by major world airlines. Worked on a stochastic distance frontier model used to assess the productive performance of a group of European airlines. Developed a detailed panel with input and output data for the private manufacturing sector of Egypt. Used parametric and non-parametric methods to examine total factor productivity improvements of this sector from 1987 to 1996, particularly in light of reforms undertaken in 1991.

**Instructor, Principles of Macroeconomics (Spring 2000-Spring 2001)**

Prepared lectures and taught the students enrolled in the class. Researched and presented articles related to concepts covered by the course material. Evaluated students' performance.

# LULLIT GETACHEW, Ph.D.

## EDUCATION

Rice University - Houston, TX
Ph.D., Economics, 2002

The Fletcher School, Tufts University - Medford, MA
Master of Arts in Law and Diplomacy (MALD)

Mount Holyoke College - South Hadley, MA
Bachelor of Arts Degree

## PUBLICATIONS

"Formulating Appropriate Electric Reliability Targets and Performance Evaluations," 2012, with S.A. Fenrick, *The Electricity Journal*, 25 (2): 44-53.

"Cost and reliability comparisons of underground and overhead power lines," 2012, with S.A. Fenrick, *Utilities Policy*, 20: 31-37.

"Estimation of the effects of price and billing frequency on household water demand using a panel of Wisconsin municipalities," 2012, with S.A. Fenrick, *Applied Economics Letters*, 19: 1373–1380.

“Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry,” 2009, with Mark N. Lowry, *Review of Network Economics*, 8 (4): 325-345.

“Alternative Regulation, Benchmarking, and Efficient Diversification,” 2009, with Mark N. Lowry, *Dialogue: United States Association for Energy Economics*, 17 (2): 27-31.

“The Market Structure of the Power Transmission and Distribution Industry in the Developed World”, 2009, in Hunt, Lester C. and Joanne Evans (eds.). International Handbook on the Economics of Energy. Cheltenham, UK: Edward Elgar Publishing.

“The Economics and Regulation of Power Transmission and Distribution: The Developed World Case,” 2009, with Mark N. Lowry, in Hunt, Lester C. and Joanne Evans (eds.). International Handbook on the Economics of Energy. Cheltenham, UK: Edward Elgar Publishing.

“Statistical Benchmarking in Utility Regulation: Role, Standards and Methods,” 2009, with Mark N. Lowry, *Energy Policy* 37: 1323-1330.

“Price Control Regulation in North America: Role of Indexing and Benchmarking,” 2009, with Mark N. Lowry, *The Electricity Journal*, 22: 63-76.

“AltReg Rate Designs Address Declining Average Gas Use,” 2008, with Mark N. Lowry, David Hovde and Steve Fenrick. *Natural Gas & Electricity* 24 (9): 13-18.

“The Policy Environment and Relative Price Efficiency of Egyptian Private Sector Manufacturing,” 2007, with R.C. Sickles, *The Journal of Applied Econometrics*, 22 (4): 703-854.

# LULLIT GETACHEW, Ph.D.

"Regulation of Gas Distributors with Declining Use Per Customer", 2006, with M.N. Lowry and S. Fenrick, *Dialogue: United States Association for Energy Economics*, 14 (2): 17-21.

"Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors," 2005, with M.N. Lowry and D. Hovde, *The Energy Journal*, 26 (3): 75-92.

# INTRODUCTORY EVIDENCE

1. There are two central purposes of Enbridge Gas Distribution's ("Enbridge", or the "Company") application for approval of 2013 rates.

2. The first purpose is to implement into the Company's 2013 rates the impacts of rulings or decisions already made by the Ontario Energy Board (the "OEB", or the "Board") on important matters.

3. The second purpose is to effect a cost of service rebasing of Enbridge's rates for 2013, following five years of Incentive Regulation ("IR"). Enbridge's rates have not been re-set on a cost of service basis for six years (the last cost of service case was for 2007).

4. This Introductory Evidence provides an overview of the aspects of Enbridge's application that address each of these two central purposes. In addition, this evidence addresses the Company's performance relative to its peers during the IR term, and provides information about the impacts of its proposed 2013 rates.

## A. Implementation of OEB Rulings or Decisions

5. During the IR term, the OEB has made rulings or decisions which could not be implemented into rates until the current IR term expires (which will occur as of January 1, 2013). Through its application, Enbridge seeks approval of the implementation of these items into its 2013 rates.

6. One ruling that has been made by the Board relates to the cost of capital and, specifically, the formula used to determine a utility's return on equity ("ROE"). In its

EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, the Board approved a new formula for determining ROE.

7. The Board has indicated that the ROE determined in accordance with the new ROE formula set out in the Cost of Capital Report is to be implemented into a utility's cost of capital, and rates, through a cost of service application, and not in a rate adjustment proceeding during the IR term.

8. As this is Enbridge's first cost of service case since the Cost of Capital Report was released, Enbridge seeks implementation of the ROE determined in accordance with the formula approved in the cost of capital proceeding.

9. The increment to Enbridge's 2013 deficiency resulting from implementation of the new Board-approved ROE formula is approximately $20.4 million, as explained at Exhibit A2, Tab 4, Schedule 1.

10. In this application, Enbridge also seeks implementation of the Board's recent decision with respect to the Company's customer care and Customer Information System ("CC/CIS") costs for 2013.

11. In the EB-2011-0226 proceeding, the Board approved a settlement agreement which set out the annual revenue requirement for Enbridge's CC/CIS services over the period from 2013 to 2018. In that case, the Board concluded that the six-year approved revenue requirement would provide ratepayers with smooth and reasonable rates for customer care and CIS services[1]

[1] EB-2011-0226 Transcript, page 57.

12. The 2013 CC/CIS revenue requirement approved by the Board in EB-2011-0226 is $110.2 million (based upon the current forecast of "customers"). This Board-approved 2013 CC/CIS revenue requirement represents an increment of approximately $11 million over the comparable amount for 2012.

13. Most of this increment occurs because ratepayers received the benefit of the Capital Cost Allowance ("CCA") on the CIS asset over the first years of its existence, rather than over the entire life of the asset. What that means is that, from 2007 to 2012, the average annual CIS revenue requirements, as calculated through a previous 2007 Settlement Agreement[2], were relatively low.[3] As of January 1, 2013, when all of the CCA benefit has been credited to the CIS revenue requirement during previous years, the annual CIS cost to be recovered in the remaining years of the asset's economic life will necessarily increase. Through the 2007 Settlement Agreement, all parties were aware that CIS-related revenue requirement would increase substantially at the end of the term of the Settlement Agreement, and agreed that Enbridge would recover the full revenue requirement associated with the new CIS, throughout its economic life.[4]

14. The total 2013 deficiency impact resulting from implementation of the ROE and CC/CIS rulings or decisions is about $31.4 million, as compared to the amounts included in the Company's rates for 2012.

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[2] Exhibit N1, Tab 1, Schedule F in the EB-2006-0034 proceeding.

[3] This is because during that period the Company received a timing benefit of lower taxes associated with a full Capital Cost Allowance (CCA) for IT hardware and software related to the new CIS asset. The CCA allowance provided tax timing benefits to be recognized by Enbridge and customers through 2012 in relation to the CIS asset's ten year economic life. Under the smoothing approach used in the 2007 settlement agreement, all of the CCA timing benefit was spread through the first five years of the economic life of the CIS asset.

[4] Exhibit N1, Tab 1, Schedule F in the EB-2006-0034 proceeding, at p. 13.

B. Cost of Service Rebasing

15. As stated, the second purpose of this application is to effect a cost of service rebasing of Enbridge's rates for 2013. The Company's rates have not been set on a cost of service basis since 2007 (in the EB-2006-0034 case).

16. The total deficiency resulting from Enbridge's proposed cost of service rebasing, exclusive of the approval of the implementation of the ROE and CC/CIS matters referred to above, is about $59.9 million (as compared to amounts that 2012 interim rates were designed to collect).

17. This is Enbridge's first rate application following the end of the term of the five-year IR plan approved in EB-2007-0615. The parameters of the IR plan were set out in a settlement agreement reached by the parties to the EB-2007-0615 proceeding and approved by the Board (the "IR Settlement Agreement").

18. Among the many issues with respect to the IR plan addressed in the IR Settlement Agreement was the subject of rebasing – this is dealt with under heading 13 of the Agreement. Specifically, the issue stated under heading 13 of the IR Settlement Agreement was as follows: "What information should the Board consider and stakeholders be provided with at the time of rebasing?"

19. On this issue, the Board-approved Settlement Agreement states as follows:

> Subject to the settlement of Issue 8.1, Enbridge agrees to provide a full cost of service filing (Phase I & II) at the time of rebasing, regardless of whether it applies to set rates for 2013 on a cost of service basis or otherwise.

20. Issue 8.1 of the IR Settlement Agreement dealt with the term of the IR plan and contemplated that, in the fourth year of the plan, a consultation could be convened to consider whether an extension of the IR plan for up to two years is warranted.

21. Enbridge is not seeking an extension of the IR plan, but it has indeed consulted with parties. Through a series of meetings in 2011, the Company met with a number of ratepayer groups, to discuss their perspectives and issues about Enbridge's next rate hearing following the end of the current IR term. As part of those consultations, Enbridge provided the stakeholders with its perspective about challenges being faced during the IR term that would have to be addressed in upcoming proceedings. Subsequently, Enbridge hosted a session for all stakeholders in November 2011 at which the Company provided information about several of the issues and challenges that Enbridge would be addressing in its 2013 rate application. This provided an opportunity for informal dialogue and information sharing in advance of the filing of this application.

22. The IR Settlement Agreement contemplated that Enbridge would provide a full cost of service filing regardless of whether it would be applying for 2013 rates to be set on a cost of service basis. At this time, in accordance with the IR Settlement Agreement, Enbridge is providing a full cost of service filing in support of its request for approval of 2013 rates.

23. In fact, Enbridge is applying for 2013 rates to be set on a cost of service basis. At this time, Enbridge believes that a full cost of service rebasing in 2013 is the best way to establish rates following the conclusion of the IR plan.

24. Enbridge believes that a full and fair rebasing on a cost of service basis should not be influenced or affected by a presumption about future regulatory models. The point of "rebasing" is to get the base right and not to create a base that is slanted one way or the other due to particular views about future models. The fact is that no party can know how Enbridge's rates will be set in future years, after 2013. Thus, any decision in this proceeding should not be impacted by whether Enbridge's rates

for 2014 and beyond are expected to be set by way of cost of service, some form of incentive regulation or another method.

25. The Company's pre-filed evidence sets out the various elements of its 2013 cost of service, in accordance with the Board's minimum filing requirements.

26. In its Natural Gas Forum Report ("NGF Report"), the Board stated a number of conclusions about the purposes of "rebasing" at the end of an IR term. At page 25 of the NGF Report (at page 25), the Board stated that:

> Each IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review. The Board's view is that a thorough cost-of-service rebasing must occur at the end of each IR plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and their benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility.

Enbridge's 2013 cost of service rate application filing is responsive to these conclusions.

27. As explained below, Enbridge's 2013 cost of service is influenced by a number of factors. On the one hand, the Company's costs are lower than they would otherwise be as a result of the productivity initiatives undertaken and efficiency gains realized through the five year IR term from 2008 to 2012. The impact of those gains is being passed on to ratepayers through this cost of service rebasing, in accordance with the Board's expectations from the NGF Report. On the other hand, Enbridge is facing a number of substantial cost pressures which contribute to significant increases in costs as compared to the Company's costs that were included in the base rates established in 2007 before the current IR term. Each of these items

(productivity gains and cost pressures) is explained below, followed by an overview of several of the main components of Enbridge's 2013 cost of service application.

Productivity Gains

28. Through the course of the IR term, Enbridge evaluated the way it goes about its business in an effort to find as many productivity and efficiency gains as possible. It should be noted, though, that Enbridge was already an efficient and relatively low-cost distributor at the time that it began the IR period (as confirmed in the Concentric Energy Advisors Benchmarking Study, which is filed at Exhibit A2, Tab 1, Schedule 2 and is discussed below). This necessarily limited the productivity gain opportunities available to the Company through the IR term.

29. That said, due to its focus on doing more with the same or less resources than before, Enbridge achieved significant productivity gains during IR. These efficiency gains were achieved throughout the Enbridge organization, and primarily relate to reductions in the Company's Operations and Maintenance ("O&M") costs, as compared to what those costs would be in the absence of such efficiency gains.

30. In summary, Enbridge was able to achieve significant productivity and efficiency gains through items such as targeted spending on projects with future benefits, optimizing various aspects of operations, enhancing revenues from various activities, optimizing financing costs and prioritizing project spending.

31. The Company's pre-filed evidence regarding these productivity and efficiency gains is set out in the descriptions of the Company's departmental O&M budgets for 2013, which are filed at Exhibit D1, Tabs 10 to 22. This reflects the fact that the impacts of the productivity initiatives are best seen in the individual areas where those initiatives were directed and undertaken. Some of the gains are also seen in the

Company's other evidence related to capital spending, cost of capital and operating revenues.

32. The Company's productivity and efficiency gains can also be seen in the fact that it has maintained very low rate increases over the IR term (less than 0.5% per year on average), at the same time as the overall inflation rate has been higher (approximately 1.75% per year on average). This matter is discussed further below.

33. As a result of Enbridge's cost of service re-basing in 2013, the benefits of these productivity gains will be passed on to ratepayers. The outcome of rebasing the productivity gains is that rates will be lower than they would have been but for the achievement of efficiencies during IR.

Cost Pressures

34. Notwithstanding the productivity gains achieved during the IR term, there are also cost pressures that have a strong impact on Enbridge's 2013 cost of service rebasing. These costs pressures are significant contributors to the Company's overall revenue deficiency for the 2013 Test Year.

35. These cost pressures include the effects of inflation, cost challenges in particular areas such as employee compensation, an increasing customer base and declining average volumes. Each is discussed below.

(i) Inflation

36. Over the period from 2008 to 2012, the inflation underpinning the rate-making process, i.e. Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD") has averaged approximately 1.75% per year. The actual figures are the following:

| Year | Inflation Rate (GDP IPI FDD) | Reference |
|---|---|---|
| **2008** | 2.04% | EB-2007-0615, Ex B-2-1 |
| **2009** | 1.54% | EB-2008-0219, Ex B-1-3 |
| **2010** | 2.73% | EB-2009-0172 Ex B-1-3 |
| **2011** | 0.72% | EB-2010-0146 Ex B-1-3 |
| **2012** | 1.72% | EB-2011-0277 Ex B-1-3 |

This represents a cumulative impact of approximately 9% over the course of the IR period. This cumulative inflationary increase of 9% has affected most of Enbridge's costs.

37. Over the same period, Enbridge's rates have not grown at the same pace. Indeed, over the years from 2008 to 2012, the Company has been able to maintain rate increases below 1% annually. The amounts of Enbridge's annual rate increases (for average residential customers) are set out in the following chart:

| Year | Distribution Rate Increase | Reference |
|---|---|---|
| **2008** | 0.1% | EB-2007-0615 |
| **2009** | 0.5% | EB-2008-0219 |
| **2010** | 0.2% | EB-2009-0172 |
| **2011** | (0.8%) | EB-2010-0146 |
| **2012** | 0.7% | EB-2011-0277 |

This represents a cumulative impact of approximately 1.5% over the course of the IR period (an average rate increase of only 0.3% per year).

38. The result is that there has been a growing gap between many of the Company's costs, and the amounts included in revenue requirement and corresponding rates during the IR term. As can be seen throughout the Company's evidence in this case, six years of inflation pressures add significant costs to Enbridge's operations, as compared to 2007. This is seen, for example, in Enbridge's rising employee costs. On the other hand, Enbridge's rates over the IR term have not reflected these inflationary pressures, as the total rate increase has been equivalent to only one quarter of the total increase in inflation over the same period. That demonstrates Enbridge's efficiency and productivity success during the IR term. That success has allowed Enbridge to manage the cost increases that were being driven by inflation, through decreased costs or increased revenues in other areas. This does not mean, however, that the Company is immune to inflationary pressures. Instead, what it signals is that without the efficiency and productivity gains realized by Enbridge during the IR term, the Company's 2013 revenue deficiency and rates would be higher than those set out in this application.

(ii) Particular Cost Challenges

39. Beyond the general effects of inflation, Enbridge is also facing a number of specific and significant cost pressures which impact on its 2013 cost of service.

40. One of the biggest contributors to Enbridge's increased 2013 costs is employee compensation costs. Enbridge's costs for employee compensation are rising, both because of a higher cost per employee and because of a greater number of employees.

41. As far as the cost per employee is concerned, Enbridge must keep pace with industry-wide increases in various elements of employee compensation, including salaries, benefits and pensions, in order to attract and retain capable employees. That is particularly important in Enbridge's circumstances of an aging workforce

where succession plans must be in place to ensure that critical skills and knowledge are maintained through newer employees, in order to maintain and operate a safe, reliable and cost effective gas distribution system. This issue is addressed at Exhibit D1, Tab 3, Schedule 2.

42. Enbridge asked Mercer Canada ("Mercer") to assess how Enbridge's employee compensation compares to industry standards and Mercer came to the conclusion, seen in its report that is filed as Exhibit D2, Tab 3, Schedule 1, that Enbridge's total compensation for all employee segments, senior management, supervisory/non-management and union is within the competitive range of the midpoint of market comparators. A summary chart setting out Mercer's findings is set out below.

**Total Compensation**

| Employee Group | (#) of Enbridge Incumbents | Multiple of P50 | Below P50 Compensation: 0.5 | 0.75 | P50 = 1 | Above P50 Compensation: 1.25 | 1.5 |
|---|---|---|---|---|---|---|---|
| Sr. Management | 69 | 1.05 | | | X | | |
| Supervisory / Non-Management | 601 | 1.01 | | | X | | |
| Union | 289 | 0.95 | | | X | | |
| All | 959 | 1.02 | | | X | | |

43. While Enbridge's overall employee compensation is at a level that roughly equates with the market midpoint, cost increases are necessary to keep Enbridge at this level. Among the drivers of these cost increases are the rising cost of providing competitive benefits packages to employees. Evidence regarding the employee

compensation and workforce demographics is filed at Exhibit D1, Tab 3, Schedule 2.

44. In addition to higher costs per employee, Enbridge is facing cost pressures due to the need for a greater number of employees. As explained at Exhibit D1, Tab 3, Schedule 1 on an overall level, and in various other D-series exhibits related to the departmental O&M budgets for 2013 and to Operating Costs for 2011, 2012 and 2013, there are a number of factors influencing the need for an increased number of employees. Among these are Enbridge's growing customer base, increased safety and regulatory requirements, new distribution asset management requirements, increased customer communications expectations and new operations requirements.

45. Taken together, increased employee costs (exclusive of pension costs, which are discussed below) are a significant driver of the Company's increased 2013 cost of service. As compared to 2012 forecast costs, the Company's 2013 budget for employee costs (wages and benefits) is approximately $14.5 million higher. The increase in employee costs from 2007 to 2013 is significantly higher than that amount. These items are addressed at Exhibit D1, Tab 3, Schedule 1, and in various other D-series exhibits related to the Company's departmental O&M budgets for 2013. In total, the Company's employee costs have increased at a rate that is higher than inflation (and that is much higher than the increases in the Company's rates).

46. Evidence at Exhibits D1, Tab 3, Schedules 1 and 2 indicates that cost in 2013 of funding and servicing the Company's pension fund is estimated to be $27.7 million. This is $26 million higher than the 2007 Board Approved level of $1.7 million. While Enbridge has applied for recovery of most of this amount as a 2012 Z-factor in the EB-2011-0277 proceeding, that request has not been determined as of the time that

this application is being filed. Accordingly, this item contributes an increase of approximately $26 million to Enbridge's 2013 cost of service.

47. Beyond employee-related costs, Enbridge is also facing other particular cost pressures that are reflected in its 2013 cost of service application.

48. Among these other cost pressures are higher materials and contractor costs, both of which contribute to increasing capital and O&M budgets. Another cost pressure comes from the Company's insurance costs, which have increased by approximately 67% since 2007. Increased regulatory expectations of the Company, particularly in a rebasing year, also contribute to higher consulting and regulatory costs.

49. The Company's overall O&M and capital budgets for 2013, and the high-level drivers of additional costs in those budgets, are set out at Exhibit D1, Tab 3, Schedule 1 and Exhibit B1, Tab 2, Schedule 1.

(iii) Customer Growth/Declining Volumes

50. During the five year IR term, Enbridge will have added approximately 185,000 new customers. This is about 10% more than the Board-approved 2007 budget of 1,823,258 customers.[5]

51. The addition of this significant number of new customers has not been matched by a comparable increase in volumes of gas distributed by Enbridge. In fact, distribution volumes have decreased about 4% from the 2007 Board-approved volumes of 11,757.5 thousand cubic metres[6] to the 2012 Board-approved volumes of

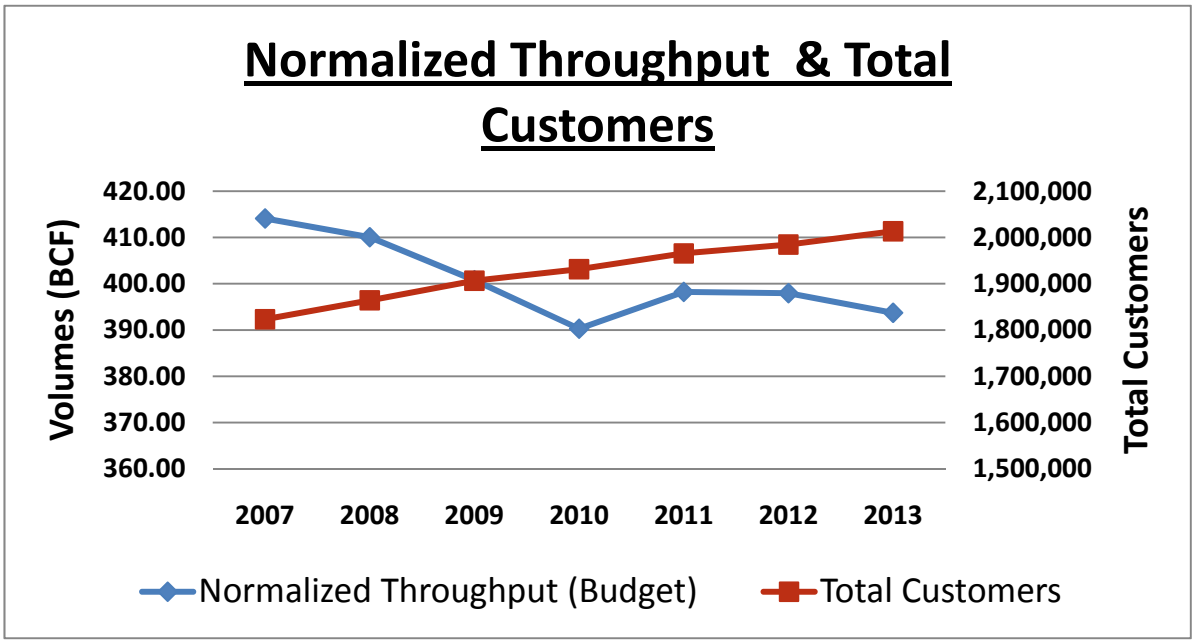
[5] EB-2006-0034, Ex C3-T2-S1 (August 15, 2006).

[6] EB-2006-0034, Ex. C3-T2-S1 (August 15, 2006).

11,300.1 thousand cubic metres.[7] A further decline to 11,179.9 thousand cubic metres is forecast for 2013.[8]

52. With another 38,896 customers forecast for 2013,[9] the Company will have added more than 220,000 customers since its last cost of service rate case in 2007. This substantial growth in customer base has caused increased cost pressures for Enbridge, in almost every area of its operations.

53. On the other hand, the absence of a comparable increase in distribution volumes has created a revenue challenge for Enbridge as it attempts to deal with these and other cost pressures. The following graph illustrates the growing disparity between customer numbers and total volumes.



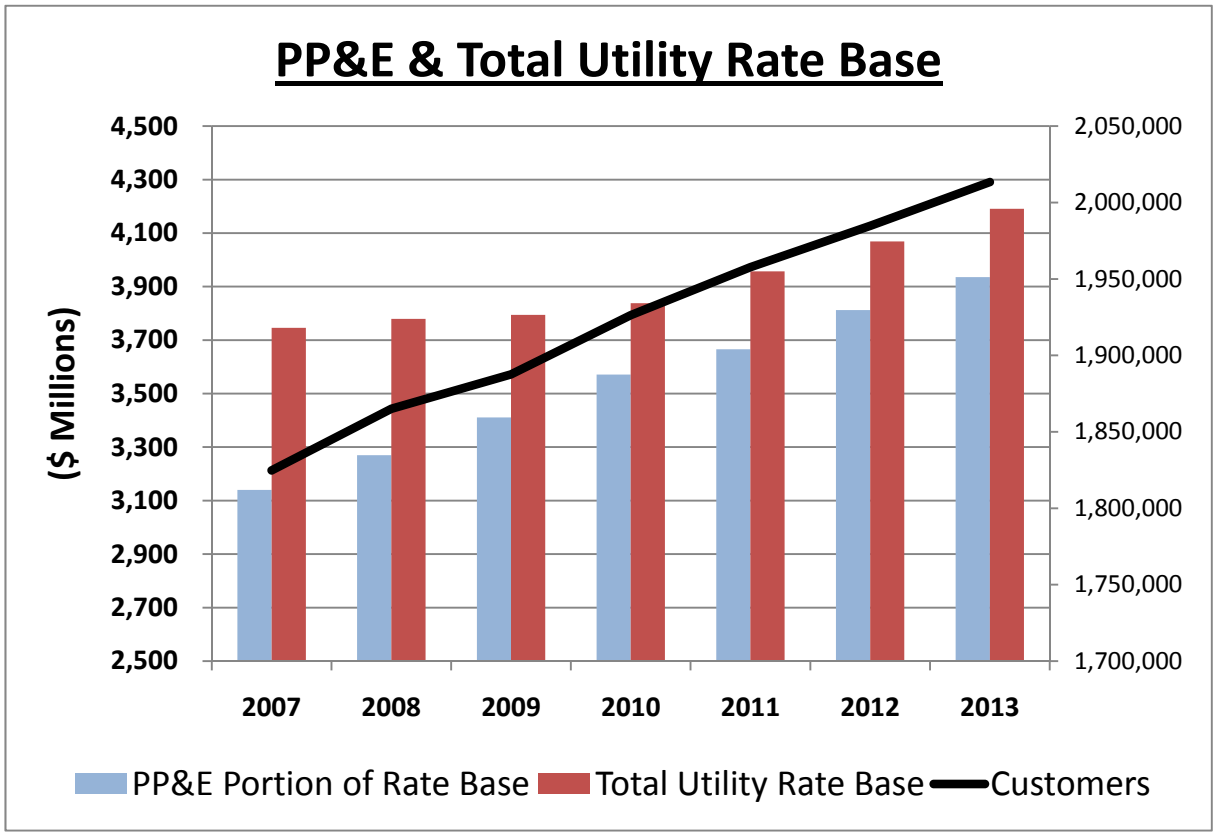

[7] EB-2011-0277, Ex. B-T1-S5 (as accepted in the Board-approved Settlement Agreement).

[8] Exhibit C1, Tab 3, Schedule 1.

[9] Exhibit B3, Tab 2, Schedule 3.

54. Inevitably, the result of this growing disparity between increasing customer numbers (which drive costs) and declining volumes (over which costs will be recovered) is to put upward pressure on rates, as seen through this cost of service rebasing.

55. One way in which the increases in customer base drive costs is through increased capital investments and rate base. As seen in the following chart, customer numbers and rate base (especially "property, plant and equipment" aspects of rate base) have both increased significantly since the time that rates were last set by cost of service in 2007. At the same time, as seen in the graph above, gas volumes have declined. At the time of rebasing, the recovery of the costs of an increased rate base over declining volumes is a significant contributor to the overall 2013 deficiency.



(iv) Income tax and financing costs

56. It should also be noted that, in addition to the above-noted cost pressures which add to Enbridge's 2013 cost of service, Enbridge's 2013 application reflects reductions in corporate income tax rates and cost of debt, as compared to 2007 base rates.

57. While ratepayers have benefitted from part of the impact of these cost reductions during the IR term, the full benefit is reflected in the Company's cost forecasts for 2013. The combined impact of these items, as set out at Exhibit A2, Tab 4, Schedule 1, Appendix A, is to reduce the Company's overall 2013 revenue requirement by $45.8 million, as compared to the amounts included in base rates.

Overview of Some Elements of the Cost of Service Rebasing

58. The following are some of the main elements of Enbridge's 2013 cost of service application. There are also other items not discussed below that form part of the Company's application. The full list of the "Approvals Requested" in relation to Enbridge's 2013 cost of service application is set out at Exhibit A1, Tab 3, Schedule 1.

(i) O&M Budget

59. For the 2013 rebasing year, the O&M budget was developed with a continued focus on safety and reliability, customer service and adherence to legislative and regulatory requirements. The Company's forecast O&M expense for 2013 is $426.1 million.

60. The Company's evidence addresses the 2013 O&M budget on an overall basis, with focus on the general areas of expense and drivers of cost increase for all of the Company's operations. As set out above, and in the evidence at Exhibit D1, Tab 3, Schedule 1, the main contributors to increases in Enbridge's O&M budget are employee-related (salary, benefit, pension and headcount). Other drivers of O&M

cost increases, as compared to 2007 base rates, include increased costs for demand side management ("DSM") activities, along with higher corporate cost allocations and increased customer care costs. As noted above, Enbridge's forecast 2013 customer care costs have already been approved by the Board (in EB-2011-0226). It is expected that Enbridge's forecast DSM costs for 2013 will be approved by the Board in the near future, as part of the EB-2011-0295 proceeding.

61. As set out in the overall O&M budget evidence at Exhibit D1, Tab 3, Schedule 1, Enbridge compared its 2013 O&M budget, on a per customer basis, with the Company's O&M expense per customer for each year since 2004. This analysis, which is reproduced below, shows that on an inflation-adjusted basis, the Company's per customer O&M costs are virtually unchanged ($197.09 in 2004 vs. $197.42 in 2013).

Enbridge Gas Distribution
Operation and Maintenance Expense
Cost Per Customer

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2013 Constant Dollars per Customer | | | | | | | | | | |
| Utility O&M Cost Per Customer [1] | 197.09 | 186.14 | 183.71 | 180.03 | 172.30 | 174.91 | 173.86 | 173.16 | 191.73 | 197.42 |
| Nominal Dollars per Customer | | | | | | | | | | |
| Utility O&M Cost Per Customer [1] | 168.40 | 162.44 | 164.11 | 164.40 | 161.02 | 165.63 | 166.76 | 167.35 | 188.49 | 197.42 |
| Number of Customers (000's) [2] | 1,676.38 | 1,724.72 | 1,782.81 | 1,824.79 | 1,865.02 | 1,887.61 | 1,926.29 | 1,957.73 | 1,984.73 | 2,013.35 |

Notes:
1. Does not include ancillary program costs, or demand side management costs
2. Number of Customers represent total unlock customers

62. Enbridge's success in achieving a low O&M cost per customer is also addressed in a Benchmarking Report from Concentric Energy Advisors ("Concentric") which is discussed later in this Introductory Evidence and is filed as Exhibit A2, Tab 1, Schedule 2.

63. The Company's evidence also addresses the 2013 O&M budget on a departmental basis, setting out further detail of the basis and needs for the overall O&M budget. The departmental O&M budget evidence is filed as Exhibit D1, Tabs 10 to 24.

(ii) Capital Budget

64. The 2013 Capital Budget for this rebasing application has been prepared in the traditional grassroots fashion with all departments within Enbridge preparing their budgets in accordance with the guidelines contained in the Budget Letter.[10]

65. The Company's planned capital expenditures for 2013 total $483.9 million. These expenditures are required to meet the Company's needs to serve its existing customer base, as well as the forecast additional 39,000 customers. Enbridge's summary evidence about its 2013 capital budget is filed as Exhibit B1, Tab 2, Schedule 1.

66. As described at Exhibit B1, Tab 3, Schedule 1, Enbridge is in the process of finalizing an Asset Plan which identifies distribution system capital requirements to address customer growth, reinforcement, integrity and reliability, and relocations needs over the next ten years (from 2012 to 2021). Enbridge expects to file its Asset Plan in this proceeding once the document is completed, likely in or around March 2012. The Asset Plan will set out the Company's distribution asset spending priorities in a manner which attempts to balance system integrity and growth requirements and the associated spending need. The timing of initiatives / programs and associated expenditures in the Asset Plan is based on priorities established through historical spend patterns, system analysis and relative risk ranking. While the Asset Plan has not been finalized, it has been used for planning and prioritizing the Company's 2012 and 2013 capital requirements. The Company believes that the Asset Plan will assist the Board in understanding the rationale for many of the

[10] Exhibit A2, Tab 2, Schedule 1.

items in the Company's 2013 capital budget, including the ways in which Enbridge's proposed capital spending in the Test Year relates to forecast expenditures in future years.

67. In addition to evidence about the Asset Plan, the Company's capital budget evidence also addresses each major component of the 2013 capital budget, organized into subject areas such as information technology ("IT"), leave to construct projects, safety and integrity projects, and storage capital projects. This evidence is filed as Exhibit B1, Tabs 3, 4, and 5.

(iii) Equity Thickness

68. Enbridge's evidence, as set out at Exhibit E2, Tab 1, Schedule 2, sets out its view that the Company's current Cost of Capital parameter values, specifically the Capital Structure component, is deficient, and that an increase in equity thickness is warranted for the following reasons:

(a) Enbridge's capital structure needs to be reflective of the business risks currently faced by the utility.

(b) The current equity ratio of 36% is significantly below that of North American peer utilities with comparable business risk and Ontario electric utilities which exhibit lower business risk.

(c) An appropriate capital structure is necessary to minimize the risk of a credit downgrade, to maintain financial flexibility, and to provide financing at a lower cost of debt.

69. Enbridge decided to retain Concentric to study the appropriate equity component of the Company's capital structure.

70. After a detailed and thorough review, Concentric concluded that Enbridge's equity thickness should be in the range of 40 to 45 percent, based on a proxy group comprised of North American gas distribution utilities with comparable risk profiles to Enbridge Gas Distribution. Concentric noted that an equity ratio of 42 percent would bring the Company in closer alignment with its industry peers and supports the maintenance of an A- credit rating to the benefit of both shareholders and ratepayers. Concentric's report is filed at Exhibit E2, Tab 2, Schedule 1

71. Consistent with the above, Enbridge's application seeks approval of an equity ratio of 42% for 2013 and beyond.

(v) Transactional Services

72. Changes to the tolls charged, and the services offered, by TransCanada PipeLines ("TCPL") have had a significant impact on the way in which gas arrives at Enbridge's franchise areas. It is expected that there will be further substantial changes to TCPL's tolls as a result of its current Mainline Tolls Application for 2012 to 2013.

73. As explained at Exhibit C1, Tab 4, Schedule 1, these changes will affect Enbridge's ability to achieve revenues from the sale of Transactional Services ("TS").

74. In view of these changes, Enbridge is proposing to reduce the amount of TS revenue that is included in rates to $6 million (from the current amount of $8 million) and to discontinue the treatment of this amount as a "guarantee".

75. In other words, as discussed in the evidence at Exhibit C1, Tab 4, Schedule 1, final 2013 rates would include the $6 million of TS revenue, but there would be a subsequent true-up in the event that actual TS revenue does not reach the $6 million amount.

(vi) Design Criteria

76. Enbridge uses Design Criteria to develop gas supply plans to meet forecast utility demand. Design Criteria refers to one or more statistical conditions and assumptions about weather, usually temperature in the form of heating degree days (degree days, or HDD). Enbridge's current Design Criteria have not been changed, or examined by the Board, since EBRO 490 in 1994.

77. Since that time, weather patterns have changed both in terms of temperature trends and temperature volatility, and the Company has added approximately 738,000 customers to its distribution system, the majority of which are temperature sensitive residential customers. The addition of temperature sensitive loads increases variability in daily demand. Enbridge's current design criterion of 39.5 HDD is based on a 1 in 5 recurrence interval while other utilities have a more conservative and realistic design criterion of 1 in 10 days. All of these items have led Enbridge to consider whether changes are required to its Design Criteria.

78. When an issue related to Design Criteria was raised in consultations in the "System Reliability" proceeding, it was suggested that the issue should be treated separately in a different proceeding. The Company is addressing the issue in this case. The Company's evidence addressing the issue is filed at Exhibit D1, Tab 2, Schedule 3.

79. The Company retained Navigant Consulting, Inc. ("Navigant") to study its Design Criteria, assess its suitability and perhaps revise it if necessary. Navigant's evidence and study, which are filed at Exhibit D2, Tab 4, Schedules 1 and 2, indicate that the current Design Criteria used by the Company are relatively risky and should be updated. In this regard, Navigant also noted that Enbridge's Design Criteria are the riskiest of surveyed gas utilities in North America. Navigant reviewed Enbridge's circumstances, and provided recommendations for updated Design Criteria.

80. Consistent with Navigant's recommendations, Enbridge is seeking approval of updated Design Criteria that more accurately reflect its potential peak day requirements. Enbridge's specific request is detailed at Exhibit D1, Tab 2, Schedule 3.

81. While Enbridge is seeking approval of the new Design Criteria for 2013, it has not included the impacts of that change in its gas cost forecast for the Test Year, for reasons described in the evidence. Accordingly, there is no impact on Enbridge's forecast 2013 revenue deficiency from this item. Instead, if this item is approved, Enbridge proposes to include the associated implementation costs (for the procurement of additional transportation) in a deferral account for later disposition. Discussion of the forecast cost implications of this request can be found at Exhibit D1, Tab 2, Schedule 1 and Exhibit D1, Tab 8, Schedule 1.

(vii) Transition from CGAAP

82. Enbridge seeks approval to use US Generally Accepted Accounting Principles ("USGAAP") for the purposes of rate setting, regulatory accounting, and regulatory reporting as of January 1, 2013.

83. In February 2008, the Canadian Accounting Standards Board determined that International Financial Reporting Standards ("IFRS") would become the new Canadian accounting standards for publicly accountable entities effective January 1, 2011, but Enbridge was able to take advantage of a one year deferral of this date to January 1, 2012. Enbridge adopted USGAAP for external reporting purposes effective January 1, 2012.

84. There continues to be uncertainty regarding the application of IFRS to Enbridge's rate regulated operations and Enbridge does not expect a rate regulated accounting

standard to be finalized by the International Accounting Standards Board in the near future.

85. Enbridge believes that USGAAP, which sets out specific guidance for entities subject to rate regulation, provides a more relevant basis upon which to evaluate and present Enbridge's regulated business.

86. As set out in its evidence at Exhibit A1, Tab 6, Schedule 2, Enbridge has weighed the advantages and disadvantages of adopting USGAAP rather than Modified IFRS for rate regulation purposes and has concluded that adoption of USGAPP will have less impact on Enbridge and its ratepayers.

C. Benchmarking

87. In order to confirm the reasonableness of Enbridge's 2013 cost of service rebasing, Enbridge took a number of steps to benchmark its performance and its 2013 budgets.

88. One step taken by Enbridge, as described above, is to compare its forecast O&M cost per customer in 2013 to the corresponding cost in other years on an inflation-adjusted basis. The result, as set out at Exhibit D1, Tab 3, Schedule 1, is that the Company's O&M cost per customer is virtually unchanged since 2004.

89. Also, as referred to above, Enbridge retained Mercer to conduct a study of employee compensation costs (filed as Exhibit D2, Tab 3, Schedule 1). Mercer concluded that Enbridge's employee costs are generally in line with the midpoint of market comparators.

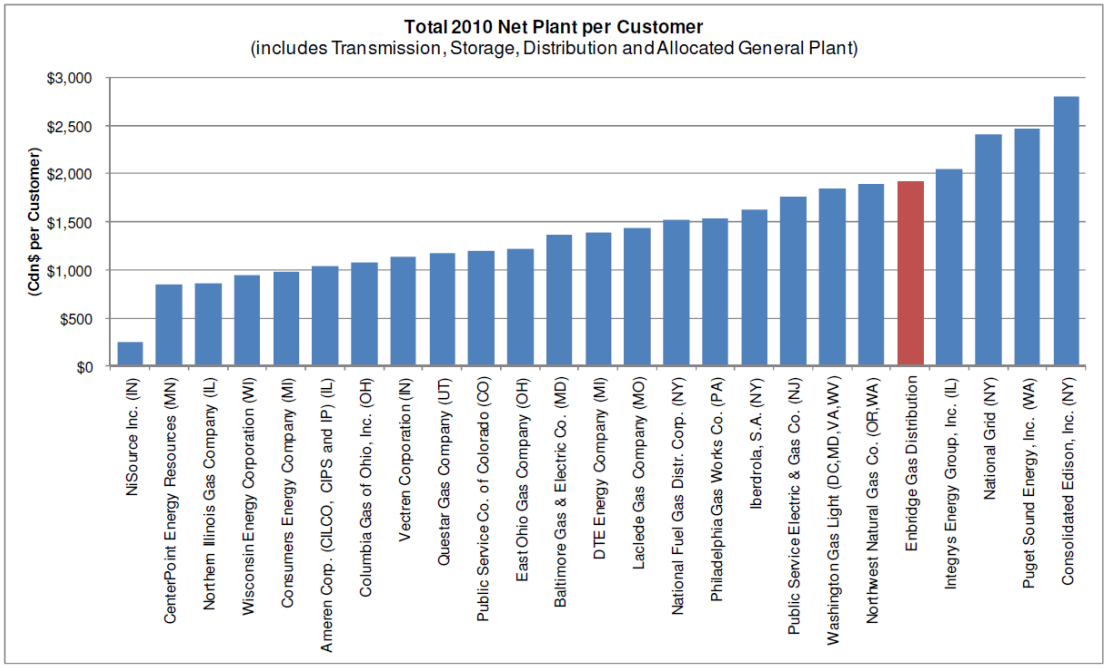
90. In preparation for this proceeding, Enbridge asked Concentric to undertake a benchmarking study, to examine the Company's performance in a number of areas

as compared to similarly situated North American gas utilities. Concentric's "Benchmarking Study" has now been completed, and is filed as Exhibit A2, Tab 1, Schedule 2.

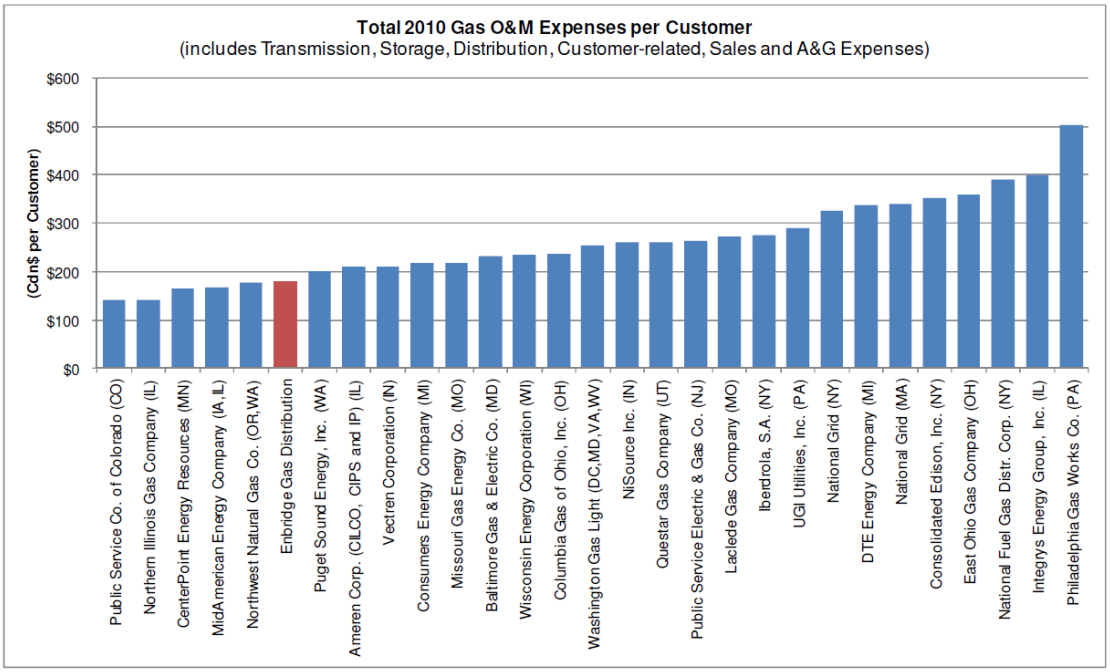
91. Concentric's independent benchmarking analysis indicates that Enbridge's cost performance has historically been among the industry's best prior to the current IR period and has improved even more so through the IR period. This demonstrates strong capital, operating and maintenance cost management by Enbridge compared to industry peers.

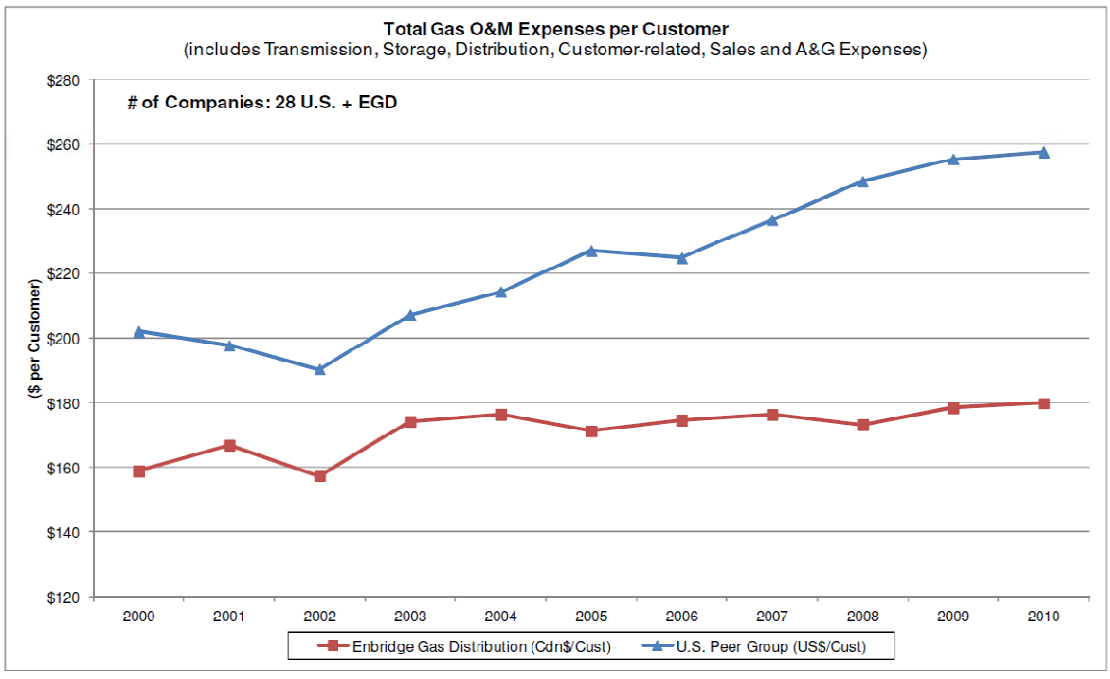
92. Among the findings in Concentric's Benchmarking Study are the following:

(a) Net plant invested per customer has risen over the past decade for Enbridge at an average annual rate of just 0.9%, while the North American peer group average grew by 2.9% annually;

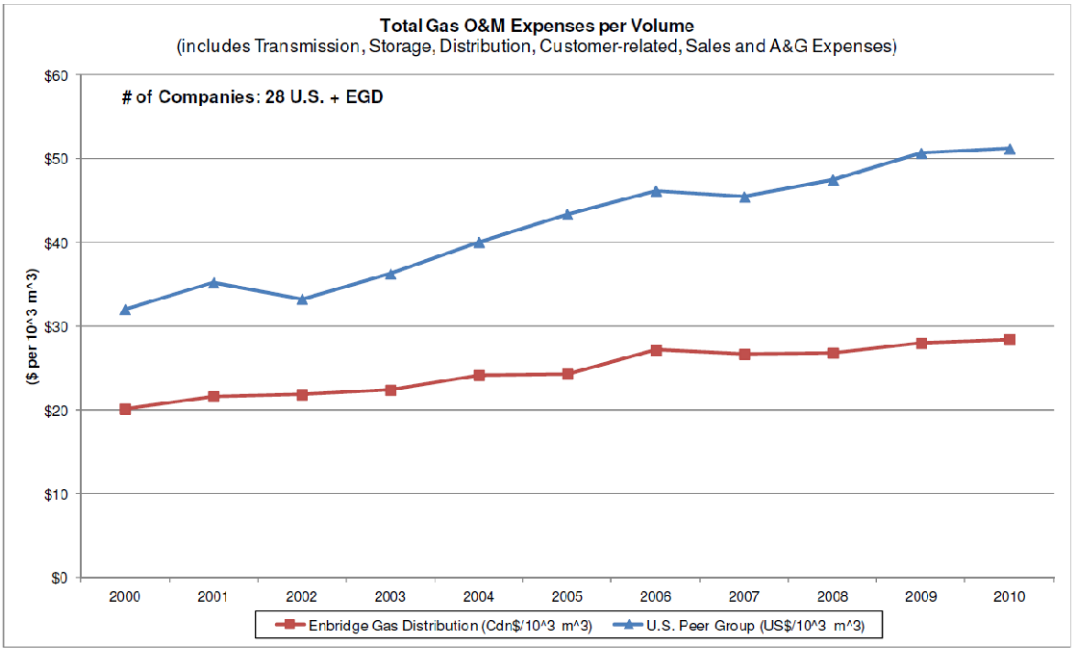


(b) O&M costs per customer for Enbridge are the 5th lowest overall amongst the peer group (3rd lowest in 2009) and the lowest of all Canadian companies. This metric has remained steady since 2002 for Enbridge whereas the US peer group average has grown significantly over the same period.

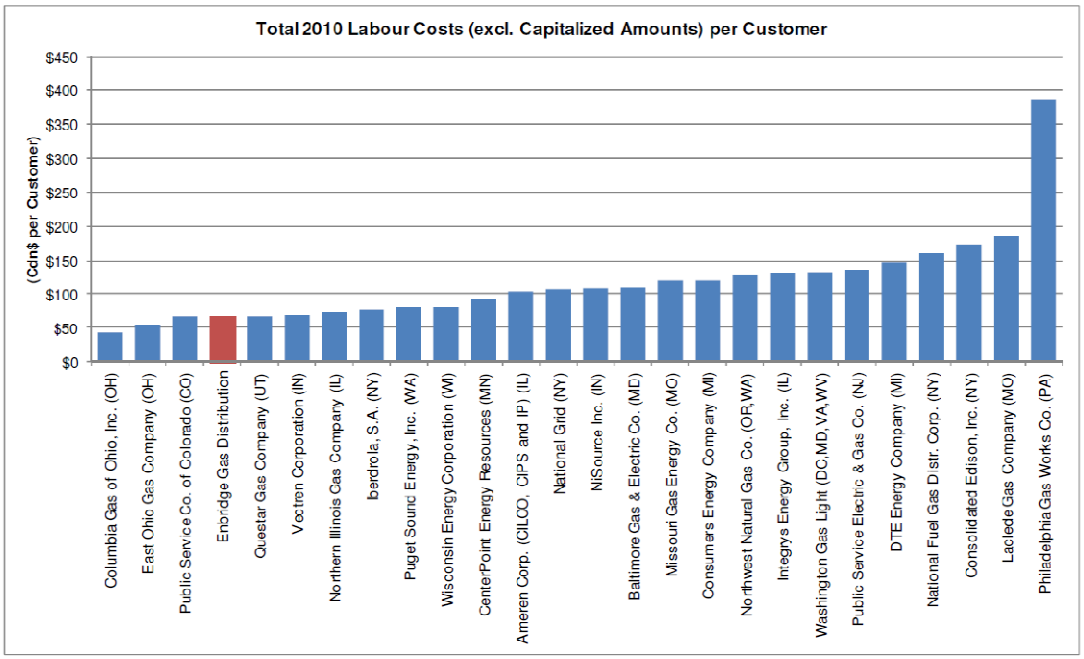


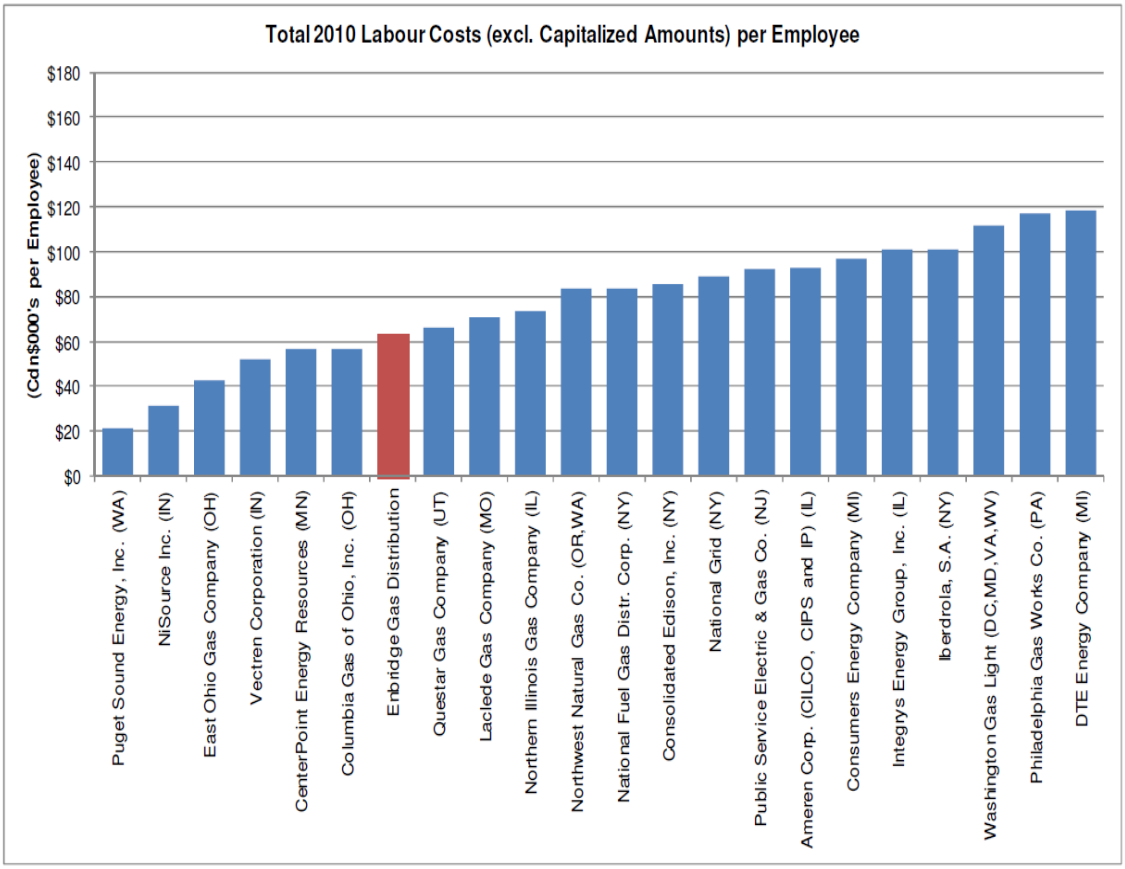
(c) Enbridge's O&M costs per unit of throughput have risen substantially slower than the US peer group's over the past decade.




(d) Labour costs for Enbridge place the Company at 4th overall on a per customer basis in 2010 and bests all Canadian peers. Further, Enbridge's labour costs have risen slower than the US peer group over the last decade.



(e) Expressed on a per employee basis, Enbridge's labour costs are lower than the average across the peer group.




93. It is not possible to benchmark the forecast costs set out in Enbridge's 2013 cost of service application against 2013 costs for other distributors, because their costs are not yet established. It is possible, however, to compare the forecast costs set out in Enbridge's 2013 cost of service application against the corresponding amounts for other distributors in prior years that are set out in the Concentric Benchmarking Report. That analysis reveals that Enbridge's forecast 2013 costs maintain its position as a cost-effective and efficient gas distribution utility, relative to other North American gas distributors.

D. Rate Impacts

94. As discussed, there are two central purposes of Enbridge's application for approval of 2013 rates.

95. The first purpose is to implement the impacts of rulings or decisions already made by the OEB related to the ROE formula to be used to calculate the Company's cost of capital, and related to the Company's CC/CIS costs, into the Company's rates for 2013.

96. The second purpose is to effect a cost of service rebasing of Enbridge's rates for 2013, following five years of IR.

97. The revenue requirement impact of the implementation of the Board's previous decisions related to ROE and CC/CIS costs is an incremental cost of approximately $31.4 million. In other words, compared to the amounts contained in the previous fiscal year's Board-approved revenue requirement, these items produce a distribution revenue deficiency of $31.4 million during the 2013 Test Year. When the Company's rates are adjusted by the Board effective January 1, 2013 to permit the elimination of this distribution revenue deficiency, Enbridge estimates that the amount charged to an average residential customer will increase by approximately $10 annually. This would result in an approximate 1.7% increase on a T-service basis (that is, total bill excluding commodity costs) or approximately 1.1% increase in the total annual bill (includes commodity costs).

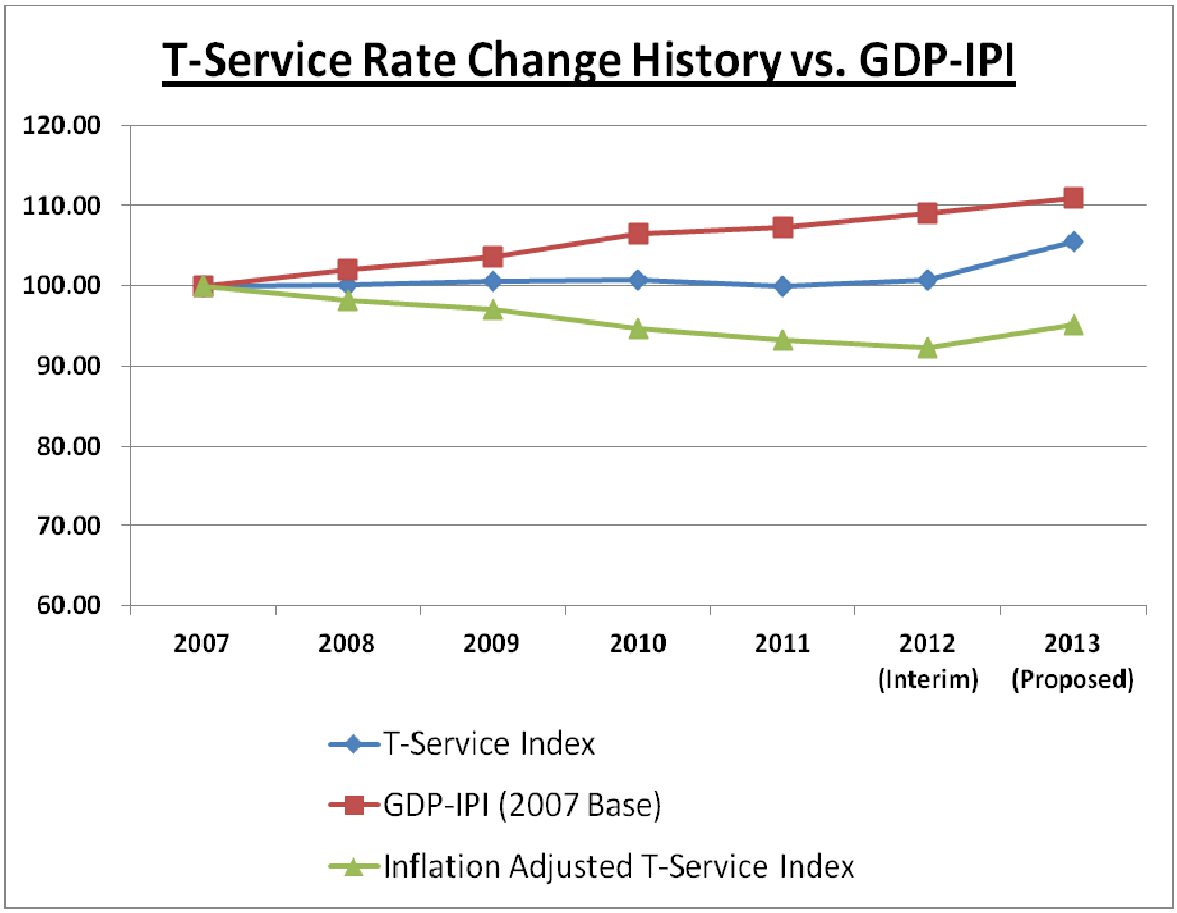
98. The revenue requirement associated with the balance of Enbridge's 2013 cost of service application is an incremental cost of approximately $59.9 million. In other words, if Enbridge's currently effective rates remain in effect, with the only change being the implementation of the Board's previous decisions described in the paragraph above, then the Company forecasts at this time that it will realize a

distribution revenue deficiency of approximately $59.9 million during Test Year. In the event that the Company's rates are adjusted by the Board effective January 1, 2013 to permit the elimination of this distribution revenue deficiency, the Company estimates that the amount charged to an average residential customer will increase by approximately $17 annually. This would result in an approximate 3.1% increase on a T-service basis (that is, total bill excluding commodity costs) or approximately 1.9% increase in the total annual bill (includes commodity costs).

99. On an overall basis, the Company's application sets out the forecast costs required to provide safe, reliable and efficient distribution, storage and transmission of natural gas for 2013. On a cost of service basis, all of these forecast costs are recoverable in the Company's rates for the Test Year.

100. When one takes into account the inflation that has impacted the Company's costs since the last cost of service rate case in 2007, the result is that Enbridge's rates are virtually unchanged over that period. In other words, Enbridge has been able to maintain its rate increases to the rate of inflation, notwithstanding challenges faced from declining volumes, system integrity issues and employee cost pressures.

101. The following chart sets out the difference between the Company's rates (on a T-service basis, which excludes commodity costs) and inflation (GDP IPI) from 2007 (the year of the last cost of service case) to 2013.




102. As seen in the chart above, the Company's proposed 2013 cost of service rates will catch-up some, but not all, of the gap that has emerged between inflation and rates. Of course, ratepayers have enjoyed the benefits of rate increases below inflation throughout the IR term. This chart also shows that, on an inflation-adjusted basis, Enbridge's rates declined during the IR term, and will still be below the 2007 cost of service level if all elements of this 2013 cost of service filing are implemented into rates for 2013.

CONCENTRIC ENERGY ADVISORS

# Benchmarking Study

*Prepared for:*

Enbridge Gas Distribution

January 27, 2012

*Prepared by:*

Concentric Energy Advisors, Inc.
293 Boston Post Road West, Suite 500
Marlborough, MA 01752

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## I. INTRODUCTION

Enbridge Gas Distribution ("Enbridge", "EGD", or the "Company") retained Concentric Energy Advisors, Inc. ("Concentric") to provide a perspective on Enbridge's performance relative to its peers during the current Incentive Regulation ("IR") plan period. Concentric conducted a benchmarking analysis, which measures EGD against both a US and Canadian peer group using a series of metrics designed to examine the relative efficiency of the Company in terms of both its capital investment and O&M expense profile.

## II. INDUSTRY BENCHMARKING METHODOLOGY

### A. Overview

Benchmarking is a commonly employed analytical technique used across a wide variety of industries to compare a company's performance against an industry group, which serves as the benchmark. Comparator companies are typically chosen from within the same industry, and screens are typically applied to narrow the field to companies with reasonably comparable operations. Company size, geography, age of assets, etc. may be used as screens, or as variables used to explain performance differences. On a given performance attribute (e.g., O&M expenditures per unit of output), companies may be grouped by quartile to determine best of class performance, and to identify performance gaps against that standard. Benchmarking is often conducted for a limited number of time periods, or even a single year.

The benefits of benchmarking are its intuitive appeal and the ability to compare against companies chosen from within the same industry. Even though no two companies face identical operating circumstances, benchmarking provides a view into industry performance and provides perspective for regulators and stakeholders. Best of class performance can be identified and performance gaps measured. Limitations of benchmarking include its inability to quantify causal relationships between operating circumstances and costs, and the relationships between inputs and outputs. Detailed data across companies beyond top line revenue and cost categories can also be difficult to glean from public sources. Further, the benchmarking comparison is a relative one, and therefore does not offer insights into optimal performance in an absolute sense.

### B. Determination of Industry Peer Group

The industry peer group used in Concentric's Industry Benchmarking study was selected according to criteria designed to produce a peer group with similar operating circumstances to EGD. The criteria, which are listed below, were also determined to allow for a peer group size that would provide a sufficiently broad perspective for industry comparisons.

- Similarity of operations to EGD: The companies in the peer group are natural gas distribution utilities; combination utilities were included if data for natural gas distribution operations was available separately from electric operations;
- Similarity of weather conditions to EGD: The companies in the peer group are located in the northern half of the continental U.S. and have average state heating degree days within +/- 40% EGD's service territory;[1]
- Similarity of size to EGD as measured by number of customers: The companies in the peer group have at least 500,000 customers within a single state; and
- Data availability: For the companies in the peer group, the necessary data for the Industry Benchmarking analysis could be accessed in reports or data bases that are generally available to the public or through subscription services.

These criteria resulted in a group of 28 U.S. natural gas utilities, comprised of 45 individual operating subsidiaries. In addition, six Canadian natural gas utilities were chosen for comparison based upon company size, (i.e., at least 150,000 customers).[2] Similar to the U.S. peer group, some Canadian utilities were eliminated from certain analyses if the necessary data was not available. A complete list of the U.S. and Canadian natural gas utilities included in the industry peer group is provided in Figure 1.

1 The weather screen was based on Concentric's analysis of annual HDD data from 2006 to 2009 obtained for the U.S. states and Enbridge's service territory.

2 The size threshold for Canadian companies was lowered in relation to the US threshold due to the limited universe of Canadian gas companies.

## Figure 1: U.S. and Canadian Natural Gas Utilities in Peer Group – Industry Benchmarking Analysis

| No. | Company Name | Ultimate Parent Company Name | State(s)/ Province of Operation |
|---|---|---|---|
| | **U.S. Natural Gas Utilities** | | |
| 1 | Ameren Corporation | Ameren Corporation | IL |
| | AmerenCILCO | | IL |
| | AmerenCIPS | | IL |
| | AmerenIP | | IL |
| 2 | MidAmerican Energy Company | Berkshire Hathaway Inc. | IA,IL |
| | MidAmerican Energy Co. (Midwest Power Systems) | | IA |
| | Iowa-Illinois Gas & Elec. Co. | | IA,IL |
| 3 | CenterPoint Energy Resources Corp. | CenterPoint Energy, Inc. | MN |
| 4 | Consumers Energy Company | CMS Energy Corporation | MI |
| 5 | Consolidated Edison, Inc. | Consolidated Edison, Inc. | NY |
| | Consolidated Edison Company of New York, Inc. | | NY |
| | Orange and Rockland Utilities, Inc. | | NY |
| 6 | Baltimore Gas and Electric Company | Constellation Energy Group, Inc. | MD |
| 7 | Dominion - East Ohio Gas Company | Dominion Resources, Inc. | OH |
| | East Ohio Gas Company | | OH |
| | West Ohio Gas Company | | OH |
| 8 | DTE Energy Company | DTE Energy Company | MI |
| | Michigan Consolidated Gas Company | | MI |
| | Citizens Gas Fuel Company | | MI |
| 9 | Iberdrola, S.A. | Iberdrola, S.A. | NY |
| | Rochester Gas and Electric Corp | | NY |
| | New York State Electric & Gas Corp | | NY |
| 10 | Integrys Energy Group, Inc. | Integrys Energy Group, Inc. | IL |
| | North Shore Gas Company | | IL |
| | Peoples Gas Light and Coke Company | | IL |
| 11 | Laclede Gas Company | Laclede Group, Inc. (The) | MO |
| 12 | National Fuel Gas Distribution Corporation | National Fuel Gas Company | NY |
| 13 | National Grid (MA) | National Grid plc | MA |
| | Boston Gas Company | | MA |
| | Colonial Gas Company | | MA |
| | Essex Gas Company | | MA |
| 14 | National Grid (NY) | National Grid plc | NY |
| | KeySpan Energy Delivery (formerly Brooklyn Union) | | NY |
| | KeySpan Gas East (formerly Long Island Lighting Co.) | | NY |
| | Niagara Mohawk Power Corporation | | NY |
| 15 | Northern Illinois Gas Company | Nicor Inc. | IL |
| 16 | Columbia Gas Of Ohio, Inc. | NiSource Inc. | OH |
| 17 | NiSource Inc. (IN) | NiSource Inc. | IN |
| | Northern Indiana Fuel & Light Company, Inc. | | IN |
| | Northern Indiana Public Service Co. | | IN |
| | Kokomo Gas And Fuel Company | | IN |
| 18 | Northwest Natural Gas Company | Northwest Natural Gas Company | OR,WA |
| 19 | Philadelphia Gas Works Co. | Philadelphia Gas Works Co. | PA |
| 20 | Public Service Electric and Gas Company | Public Service Enterprise Group | NJ |
| 21 | Puget Sound Energy, Inc. | Puget Holdings LLC | WA |
| 22 | Questar Gas Company | Questar Corporation | UT |
| | Mountain Fuel Supply Company | | CO,ID,UT,WY |
| | Questar Gas Company | | CO,ID,UT,WY |

| No. | Company Name | Ultimate Parent Company Name | State(s)/ Province of Operation |
|---|---|---|---|
| 23 | Missouri Gas Energy Co | Southern Union | MO |
| 24 | UGI Utilities, Inc. | UGI Corporation | PA |
| | UGI Utilities, Inc. | | PA |
| | UGI Penn Natural Gas, Inc. | | PA |
| | UGI Central Penn Gas, Inc. (formerly PPL Gas Utilities) | | PA |
| 25 | Vectren Corporation | Vectren Corporation | IN |
| | Indiana Gas Company, Inc. (IN) | | IN |
| | Southern Indiana Gas and Electric Company, Inc. | | IN |
| 26 | Washington Gas Light Company | WGL Holdings, Inc. | DC,MD,VA,WV |
| | Washington Gas Light Company | | DC,MD,VA,WV |
| | Shenandoah Gas Company | | DC,MD,VA,WV |
| 27 | Wisconsin Energy Corporation (We Energies) | Wisconsin Energy Corporation | WI |
| | Wisconsin Natural Gas Company | | WI |
| | Wisconsin Electric Power Company | | WI |
| | Wisconsin Gas LLC | | WI |
| 28 | Public Service Company of Colorado | Xcel Energy Inc. | CO |
| | **Canadian Natural Gas Utilities** | | |
| 29 | ATCO | ATCO | Alberta |
| 30 | FortisBC | FortisBC | British Columbia |
| 31 | Gaz Metro | Gaz Metro | Quebec |
| 32 | Manitoba Hydro | Manitoba Hydro | Manitoba |
| 33 | SaskEnergy Inc. | SaskEnergy Inc. | Saskatchewan |
| 34 | Union Gas Limited | Union Gas Limited | Ontario |

### C. Data Sources

EGD's data is primarily based on data provided by EGD for 2000 through 2010. Data provided by the Company includes historical expense, plant, customer count, and throughput data.

The Industry Benchmarking analysis is based on data that was compiled from publicly available sources and commercially available databases for the U.S. natural gas utilities and publicly available company filings (e.g., rate case filings) for the Canadian natural gas utilities included in the peer group. The Industry Benchmarking analysis is primarily based on data from 2000 to 2010.

The following U.S. and Canadian natural gas utility cost data was used to develop the Industry Benchmarking analysis for the industry peer group:

- Sales Details
    - Total Customers – Sales & Transportation
    - Total Volumes – Sales & Transportation
- Labour Costs
    - Gas Salaries & Wages – O&M and Total

    - Total Number of Employees
    - Employee Pensions & Benefits
- Materials
    - O&M Expenses, by Major Category
- Capital
    - Gas Plant In Service, by Major Category
    - Accumulated Depreciation, by Major Category
    - Net Plant, by Major Category
- Total Miles (or Kilometers) of Distribution Mains

1. U.S. Peer Group

For the Industry Benchmarking analysis, Concentric primarily relied on data compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports").[3]

The database was checked for completeness, accuracy, and consistency. Data was gathered at the individual operating subsidiary level; data for a number of different individual operating subsidiaries was combined over the 2000 to 2010 time period to account for mergers and acquisitions in order to develop complete, consistent data series (e.g., companies that now comprise National Grid (NY) include (1) KeySpan Energy Delivery (a.k.a. KED-NY, formerly Brooklyn Union), (2) KeySpan Gas East (a.k.a. KED-LI, formerly Long Island Lighting Company), and (3) Niagara Mohawk Power Corporation). In addition, data for separate operating subsidiaries of the same parent company within a single state were aggregated at the state level.[4] Finally, gaps in data (i.e., missing data) and data inconsistencies were identified by examining line graphs for each data series for each company.

The missing/inconsistent data points were supplemented by:

[3] Concentric primarily relied on data from the Annual LDC Reports as provided through the SNLxL database. When data was not available directly through the SNLxL database, Concentric manually entered the data from the Annual LDC Reports, if possible (e.g., gas salaries and wages – O&M data was not available through the SNLxL database for most operating subsidiaries, so this data was manually entered from the Annual LDC Reports).

[4] For example, data for the gas operations of Con Edison of New York and Orange & Rockland Utilities, which are operating subsidiaries in the state of New York of Consolidated Edison, Inc. were combined.

- Data from the Uniform Statistical Reports as provided and reported through AGA's electronic Gas Utility Statistics ("eGUS") database, if it was consistent with the data and data trends in the Annual LDC Reports; or
- Calculations based on straight-line trends in the data.

Overall, approximately 3% of the data utilized in the Industry Benchmarking analysis was supplemented by data from the AGA's eGUS database and approximately 1% was based on calculations of averages and straight-line trends. Figure 2 below provides details of the data manipulations by data series utilized in the Industry Benchmarking analysis.

**Figure 2: Adjustments to Reported Data for Industry Benchmarking Database for the U.S. Peer Group**

| Data Description | Data Source | Occurrence of Adjustments | |
|---|---|---|---|
| | LDC Annual Reports | % from AGA eGUS Database | % Estimated |
| **Sales Details** | | | |
| Customers by Segment - Sales & Transportation | 2000-2010 | 3% | 0% |
| Volumes by Segment - Sales & Transportation | 2000-2010 | 1% | 0% |
| **Labour** | | | |
| Gas O&M Salaries & Wages | 2000-2010 | 9% | 5% |
| Total Gas Salaries & Wages | 2000-2010 | 4% | 1% |
| Total Number of Employees | 2000-2010 | 3% | 1% |
| A&G-Employee Pensions & Benefits | 2000-2010 | 2% | 0% |
| **Materials** | | | |
| O&M Expenses, by Major Category | 2000-2010 | 0% | 0% |
| **Capital** | | | |
| Gas Plant In Service, by Major Category | 2000-2010 | 0% | 0% |
| Accumulated Depreciation, by Major Category | 2000-2010 | 8% | 4% |
| **Distribution Mains & Services** | | | |
| Total Miles (or Kilometers) of Mains | 2010 | 0% | 2% |
| **TOTAL** | | **3%** | **1%** |

2. Canadian Peer Group

Due to data limitations, only 2009 data was collected for the Canadian peer group in order to calibrate Enbridge's operational performance against its Canadian peers, and the Canadian group in general against the US companies. Data for the Canadian peer group was collected through publicly available company filings (e.g., rate case filings) and supplemented by data from the Canadian Gas

Association's ("CGA") reports titled "Distribution & Transmission Operational Benchmarking Data".

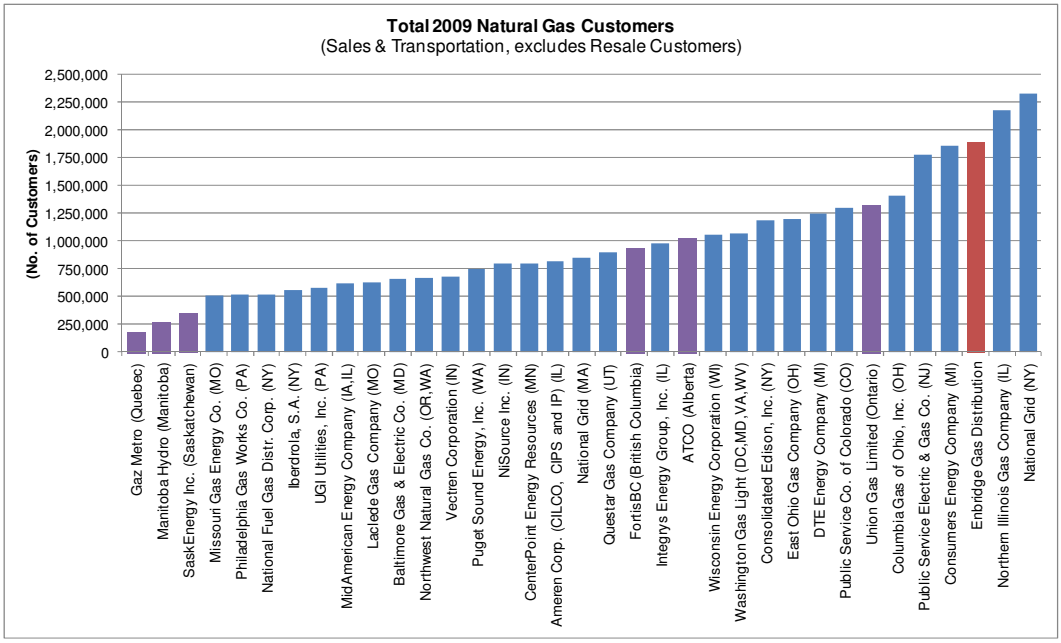
## III. INDUSTRY BENCHMARKING RESULTS

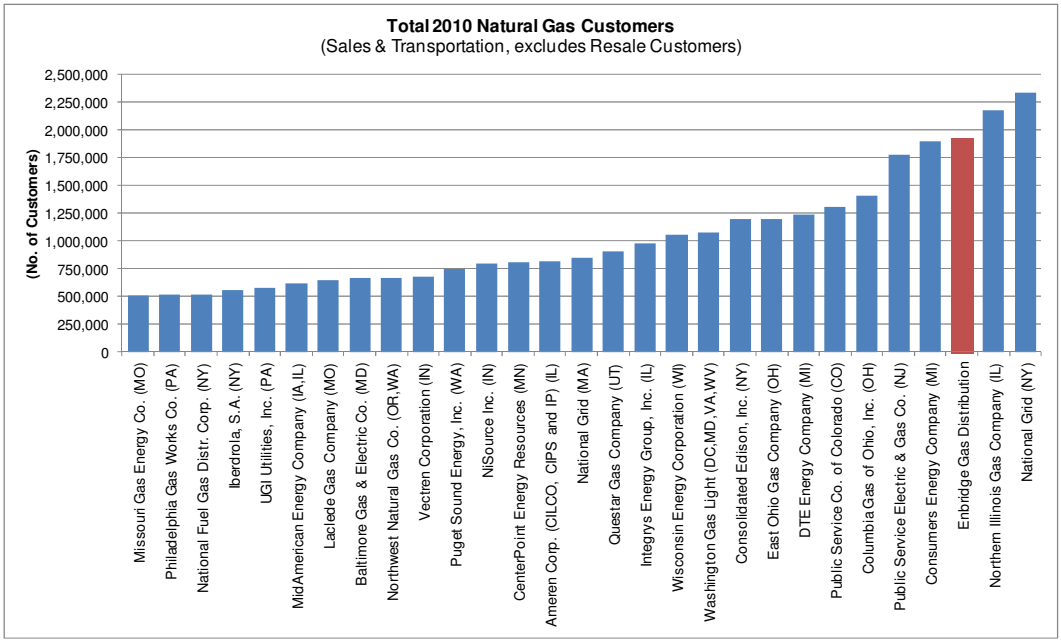
### A. Peer Group Analysis

As noted previously, Enbridge's performance is compared to a peer group of 28 U.S. and 6 Canadian natural gas utilities that were chosen based on a number of selection criteria that were designed to reflect Enbridge's operating profile and provide a broad perspective for industry comparisons. In order to provide proper context and background on the peer group, the following sections compare Enbridge's operational profile in 2009 and 2010 to the peer group.

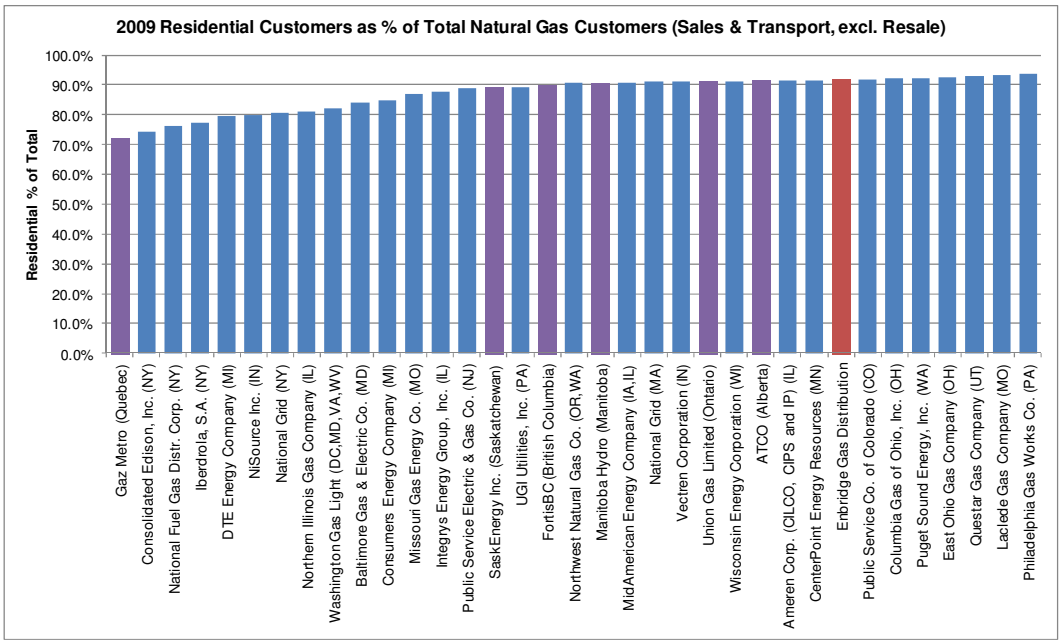
#### 1. Customer Profile

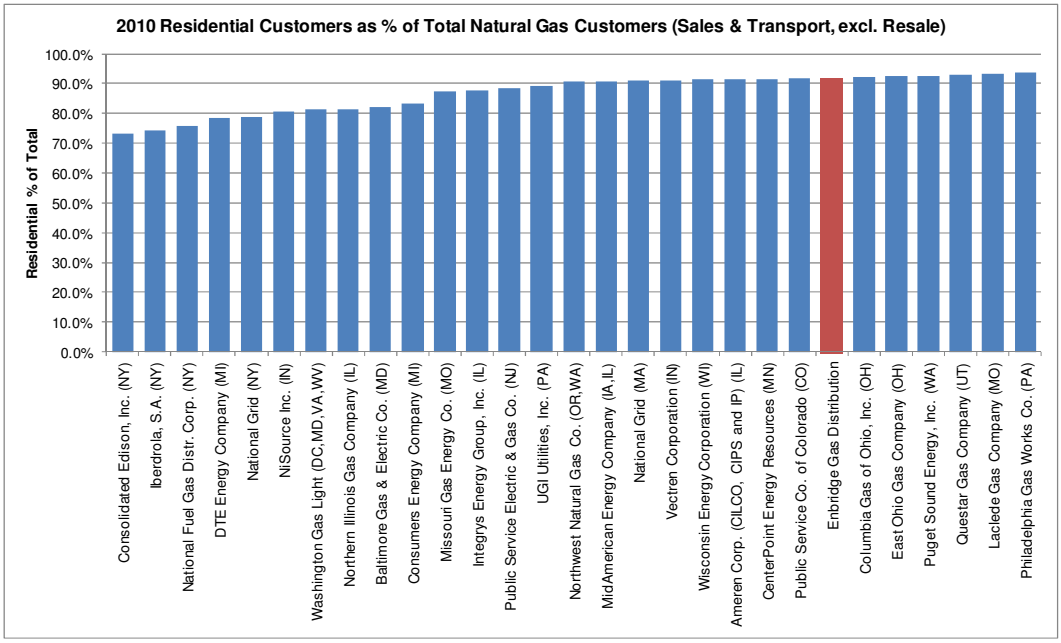
In terms of utility size as measured by the number of customers, Enbridge is the largest Canadian utility and third largest overall in the peer group. The charts below shows the total natural gas customers in 2009 and 2010 for Enbridge (in red) and each of the natural gas utilities in the peer group (with the U.S. utilities in blue and Canadian peers in purple).





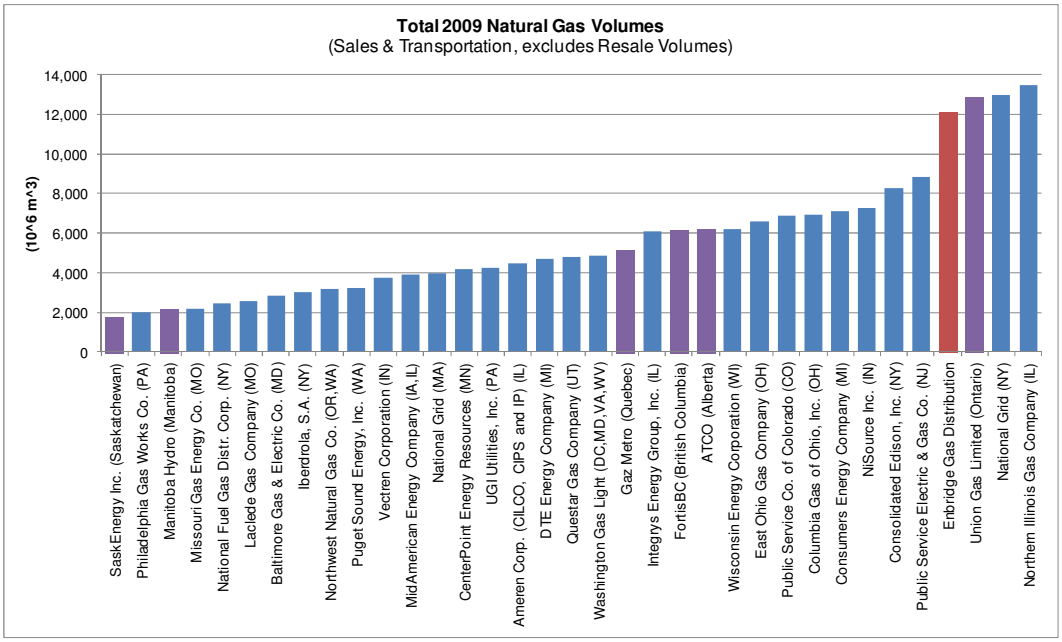

As shown in the graphs below, Enbridge serves approximately 1.9 million customers, with residential customers representing over 90% of Enbridge's customer count, based on 2009 and 2010 data. The high percentage of residential customers generally implies that, all else being equal, Enbridge may experience higher costs than utilities with fewer residential customers due to the additional capital and operating expenses associated with serving a larger proportion of smaller customers.

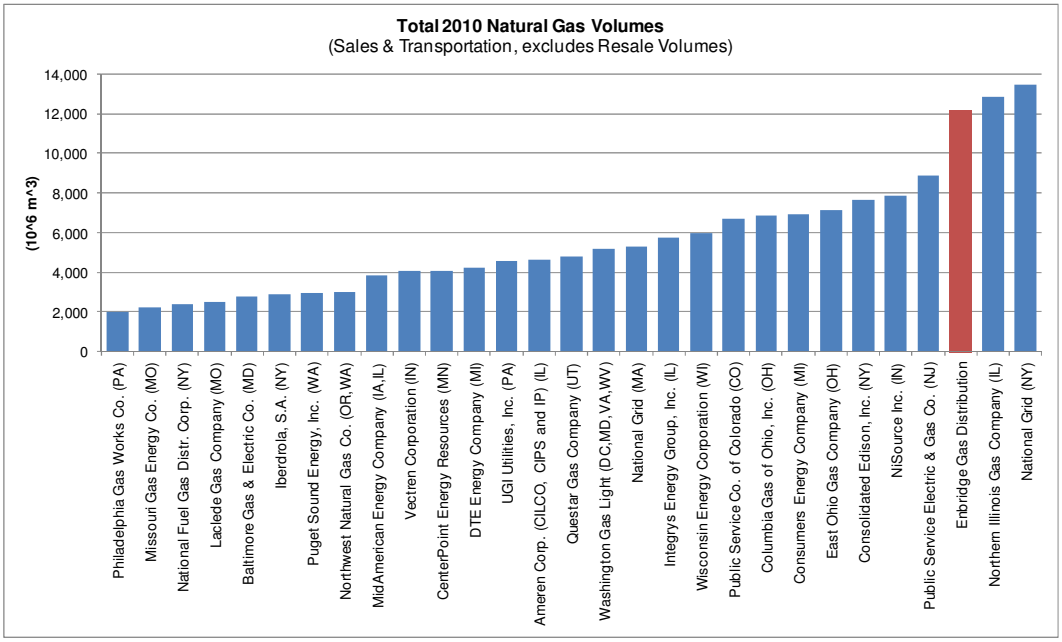




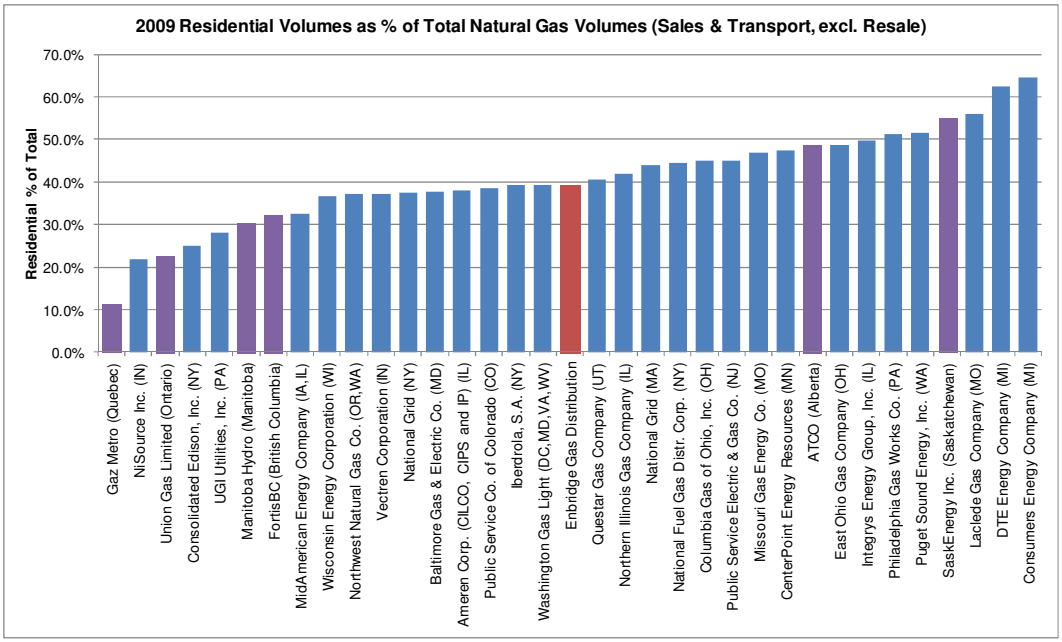

2. System Throughput

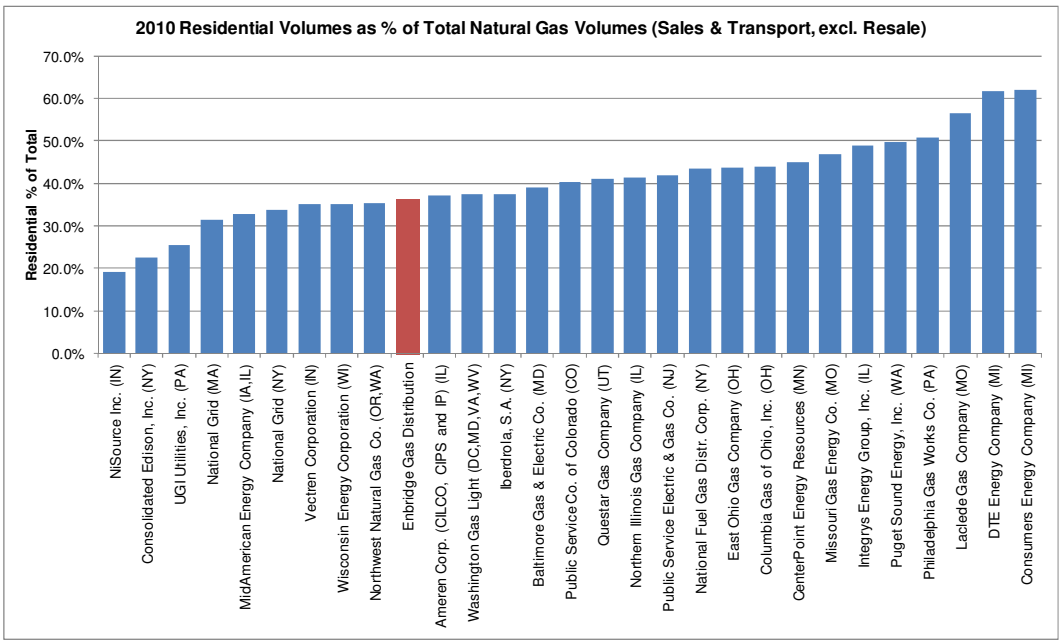
The charts below show the total natural gas volumes in 2009 and 2010 for Enbridge and each of the natural gas utilities in the peer group. As illustrated, Enbridge is the second largest Canadian utility and third largest utility compared to the U.S. peer group based on total natural gas volumes.



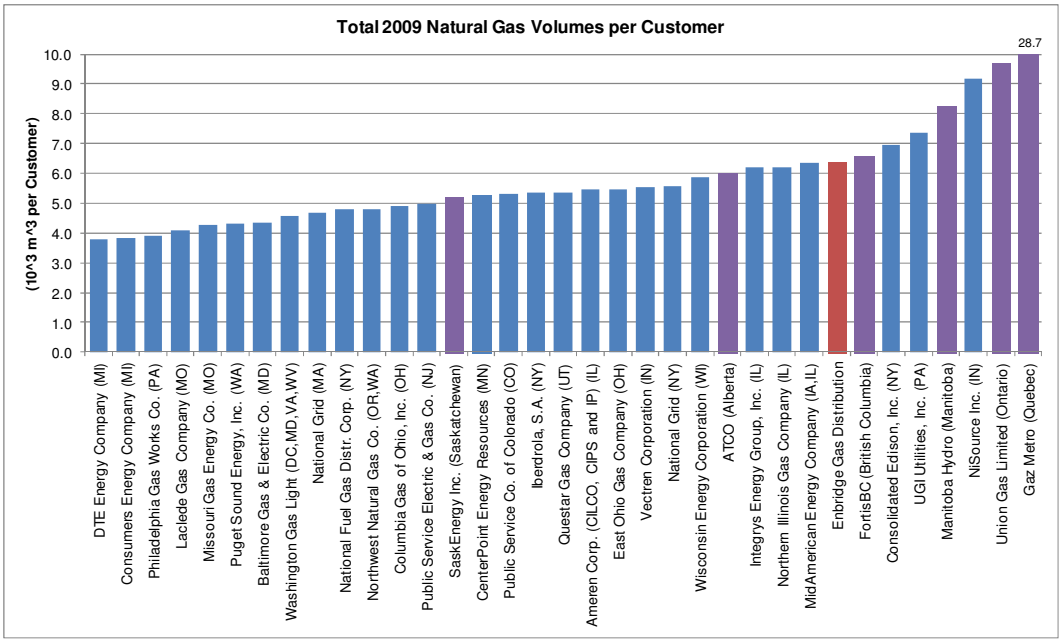


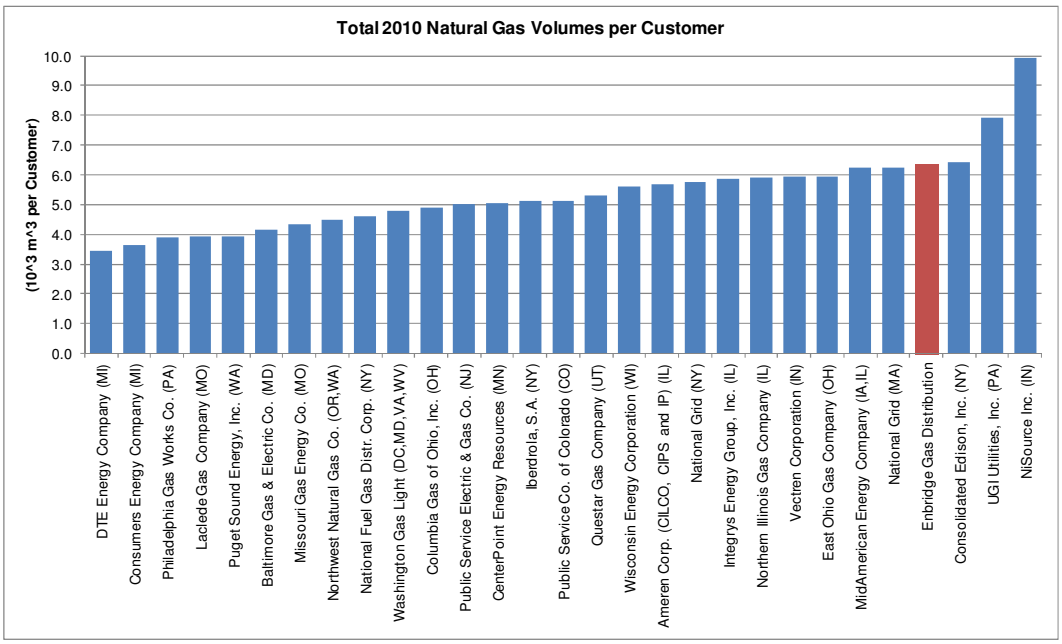

Although Enbridge's customer profile is predominantly residential, in terms of its system throughput, residential volumes only represent approximately 40% of Enbridge's total natural gas volumes. As shown in the charts below, Enbridge's residential volume profile rank is near the median in 2009 and in the second lowest quartile in 2010.





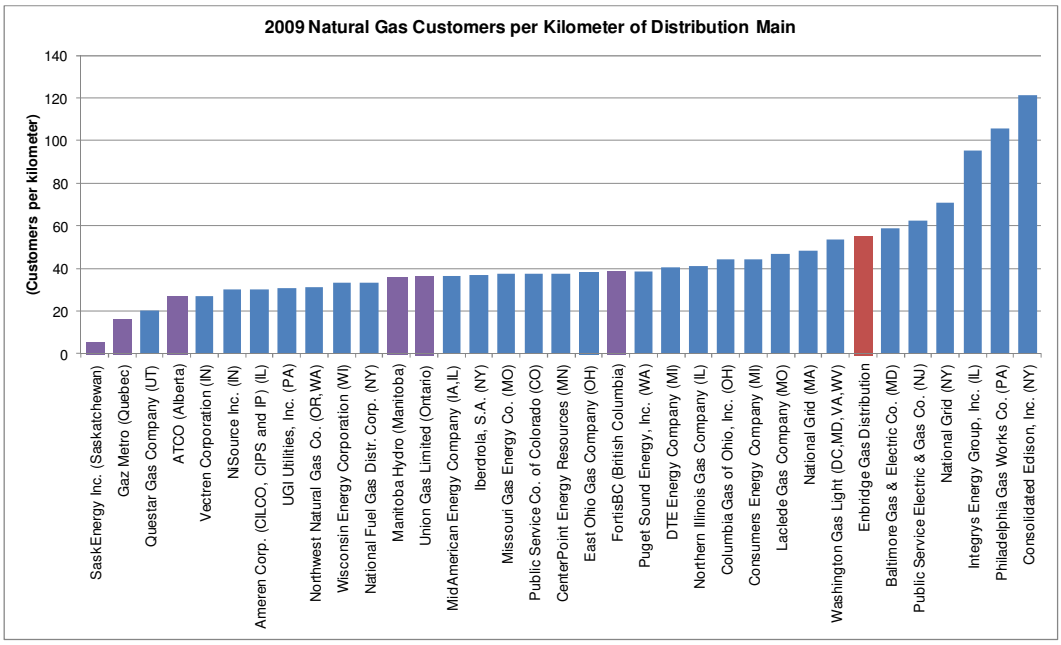

As illustrated in the charts below, Enbridge is in the top quartile in terms of natural gas volumes per customer when compared against both Canadian and U.S. utilities, and has the fourth largest volume per customer when compared against U.S. utilities.

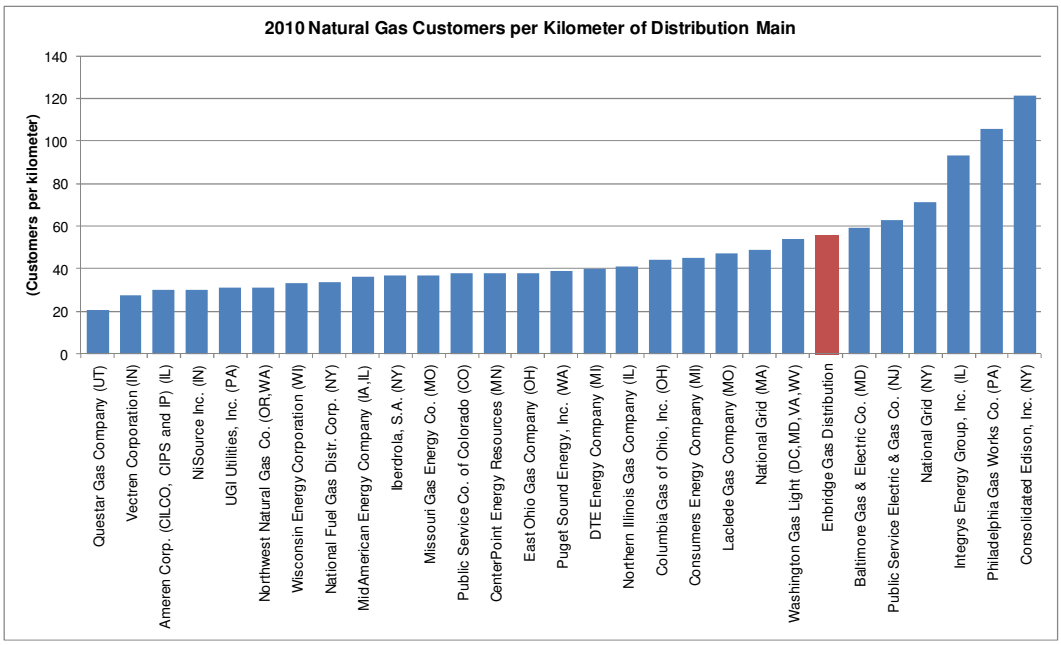




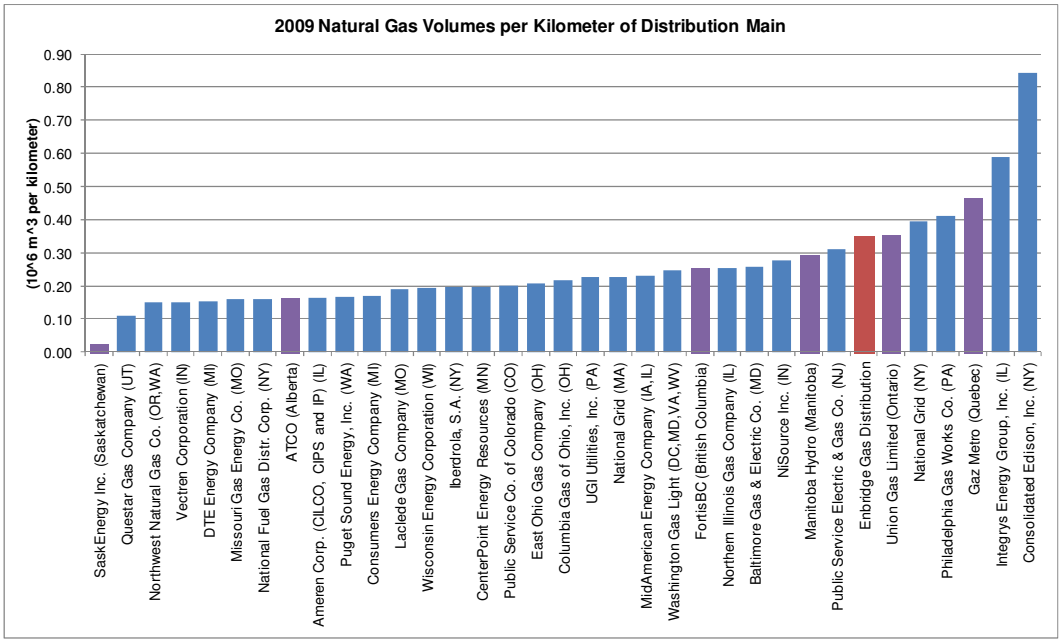

3. Customer Density

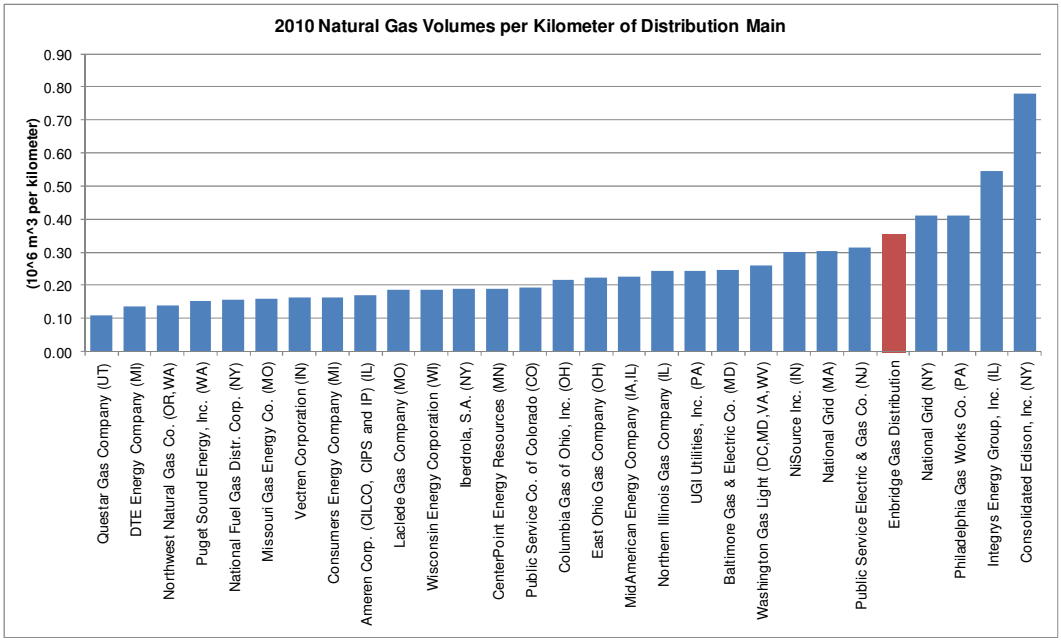
In terms of customer density (i.e., number of customers per kilometer of distribution main), Enbridge is the most dense Canadian utility and seventh most dense overall in the peer group as shown in the charts below. All else being equal, density is a favorable attribute for the cost of serving gas customers.






Similarly, as illustrated below, Enbridge ranks seventh largest overall, and fifth largest when compared to the U.S. peer group in terms of total natural gas volumes per kilometer of distribution main.





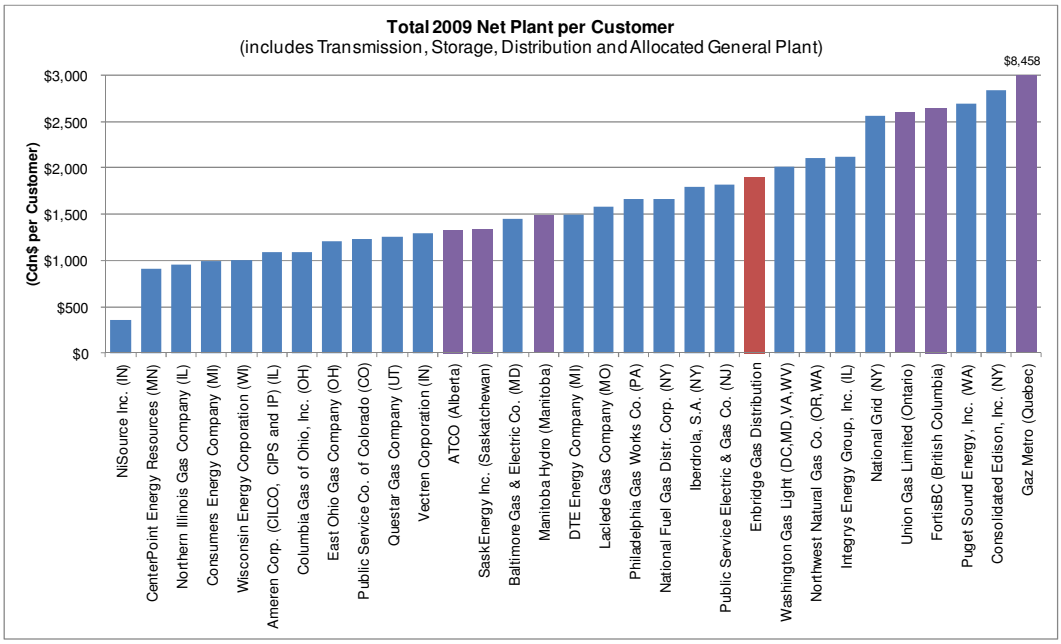

Overall, Enbridge is above average in terms of size and density as compared to the peer group, but is comfortably within the range of peer group results, indicating that the peer group is appropriate for benchmarking. Since the U.S. peer group is already comprised of the largest utilities with similar weather as Enbridge, the only way to create a peer group in which Enbridge is more towards the middle, would be to drop a number of the relatively smaller and less dense companies. Since benchmarking analysis is predicated on comparing the subject company to a sufficiently large group of comparison companies, Concentric decided to maintain the industry peer group. From a cost expectations standpoint, Enbridge's scale and customer density attributes would lead us to expect the company to operate at the upper end of the efficiency range. This is, however, somewhat mitigated by its large concentration of residential customers.

### B. Benchmarking and Trend Analysis

The following sections summarize the results of the benchmarking and trend analysis which compares Enbridge's performance against the peer group across a number of operational metrics. Enbridge's performance in 2009 and 2010 is benchmarked against the U.S. and Canadian peer group. In addition, Enbridge's longer-term performance trends are compared to the performance trends of the U.S. peer group over the 2000 to 2010 time period.

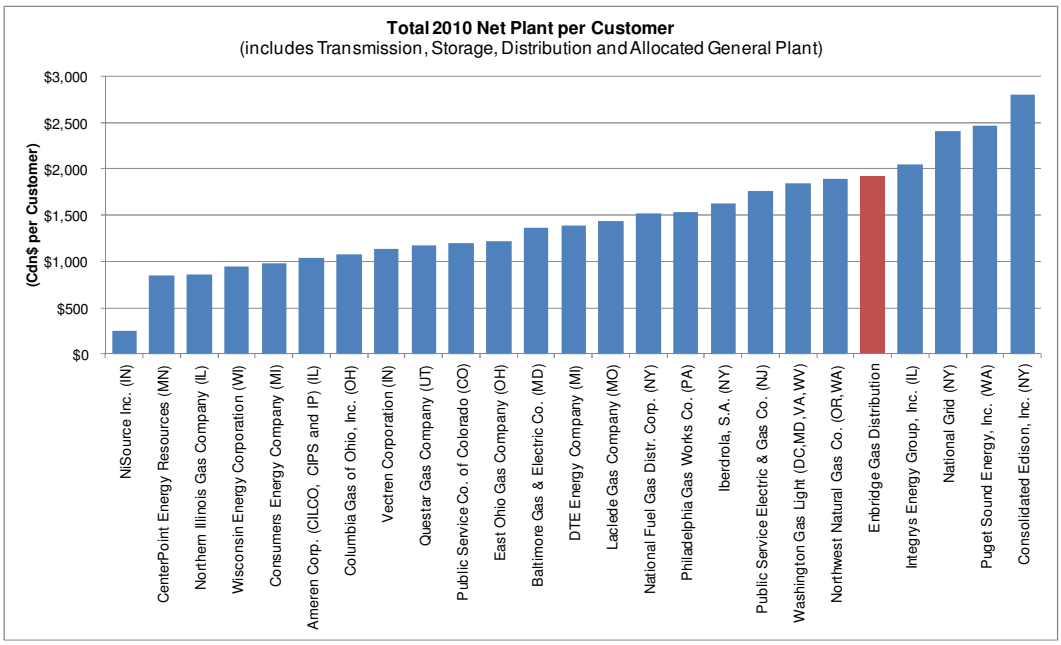
1. Net Plant per Customer and per Unit of Volume

Consistent with its high residential customer profile, Enbridge ranks tenth highest in terms of total net plant per customer in 2009 at a total of approximately $1,900 per customer. The total net plant includes transmission, storage, distribution, and an allocated portion of general plant costs. As shown in the chart below, Enbridge is the median relative to the Canadian peer group.

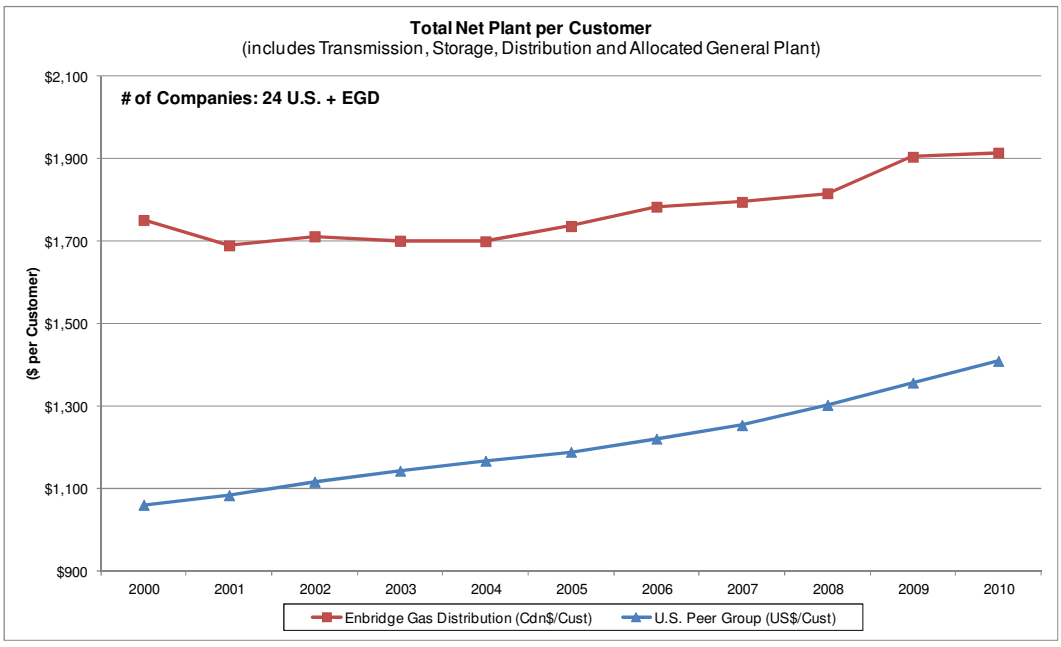



Enbridge's total net plant per customer in 2010 is consistent with its 2009 ratio at approximately $1,900 per customer. As shown in the chart below, Enbridge is the fifth highest compared to the 28 U.S. natural gas utilities in 2010.[5]

[5] Due to year-to-year exchange rate differences, one must use caution in interpreting the year-to-year benchmarking comparisons. In 2010, US company plant/customer increased in $US compared to 2009 (as shown in the line graph on page 16), but when converting to Canadian dollars, for comparison to Enbridge, the 2010 US company plant/customer numbers decreased (as seen by comparing the 2009 and 2010 bar charts). The issue is that the exchange rate in 2009 was 1.14, while in 2010 it was 1.03, causing a shift downward in the US companies when expressed in Canadian dollars. The line charts, which compare costs over the entire 2000-2010 period, are expressed in own-country US and Canadian dollars for both the peer group and Enbridge, which avoids this issue. Concentric believes that both forms of comparison (own-country and conversion to Canadian dollars) have merit, so both are utilized.

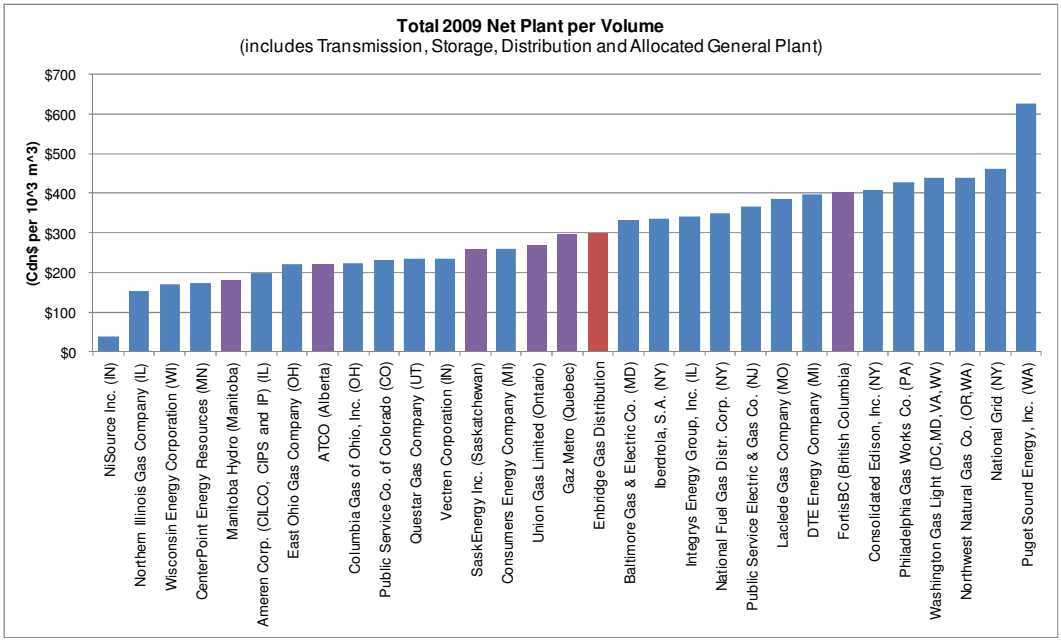


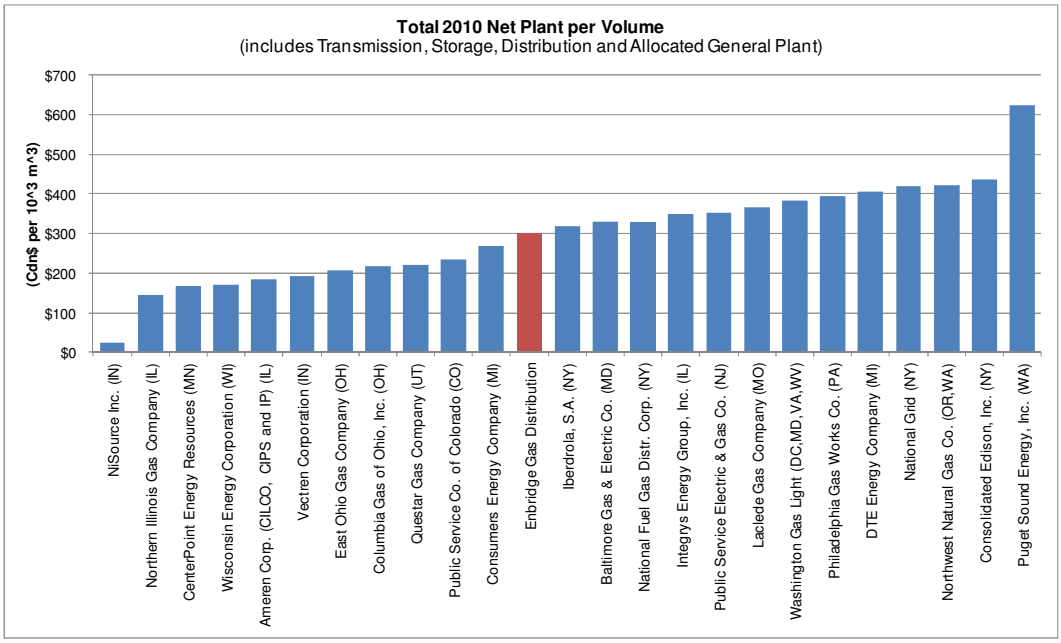

As illustrated in the chart below, both Enbridge and the U.S. peer group have experienced growth in net plant per customer over the 2000 to 2010 time period, but Enbridge's net plant per customer grew at a considerably slower rate than the U.S. peer group. Over the 2000-2010 period, Enbridge's net plant per customer grew at an average annual rate of 0.9%, while the peer group average grew by 2.9% annually.



2. Net Plant per Unit of Volume

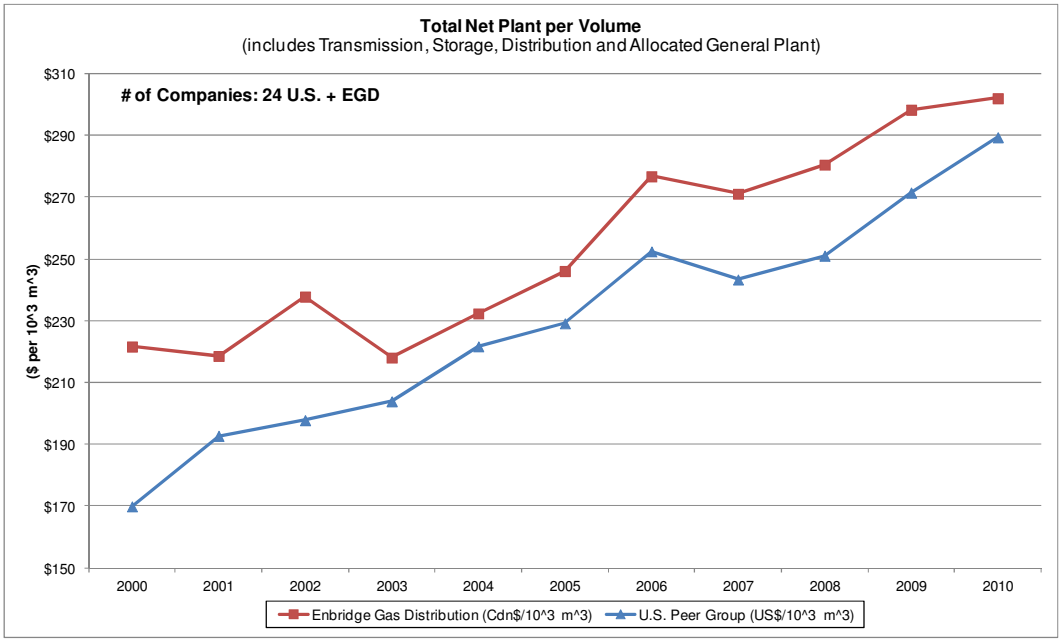
With respect to total net plant per unit of volume, Enbridge falls slightly above the average of the peer group in both 2009 and 2010, and is second highest of the Canadian peer group. Enbridge's net plant costs per volume are consistent with its high residential customer profile.



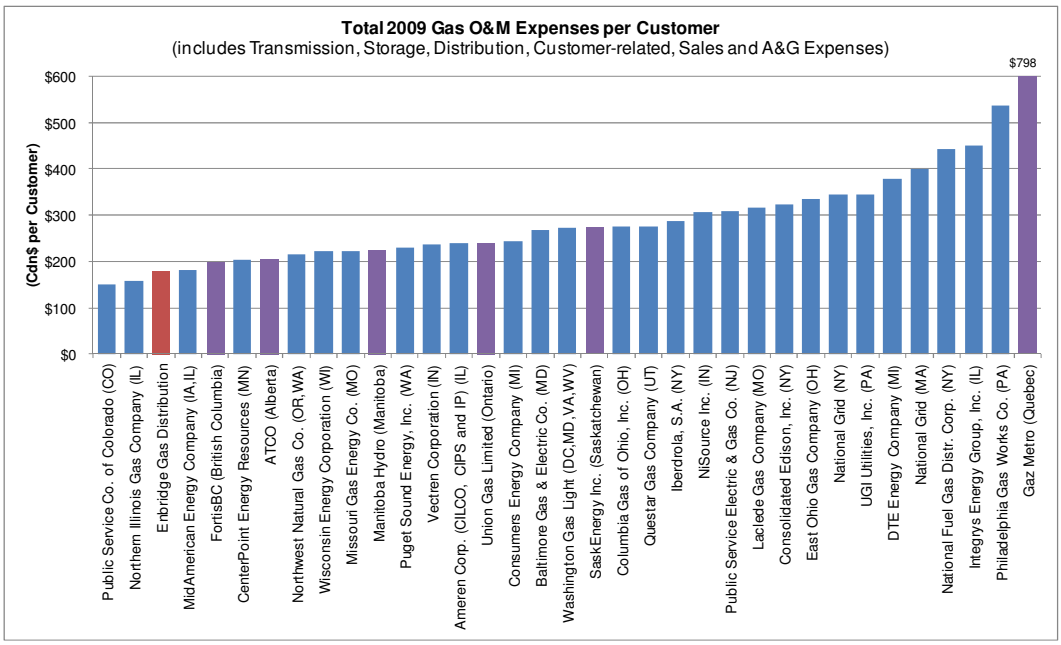

Over the 2000 to 2010 time period, Enbridge's net plant per unit of volume has steadily increased, which is consistent with the trends experienced by the U.S. peer group as gas companies and their customers responded to higher commodity prices, more efficient appliances, and conservation

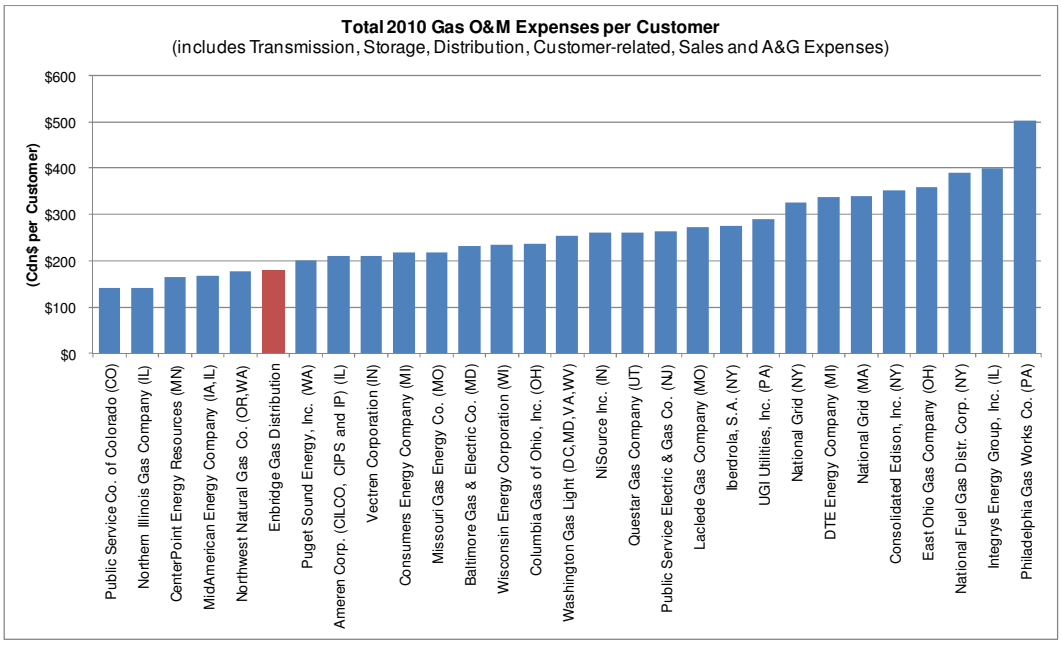
programs leading to lower use per customer, which have led to increased utilization of revenue decoupling mechanisms in both the US and Canada.



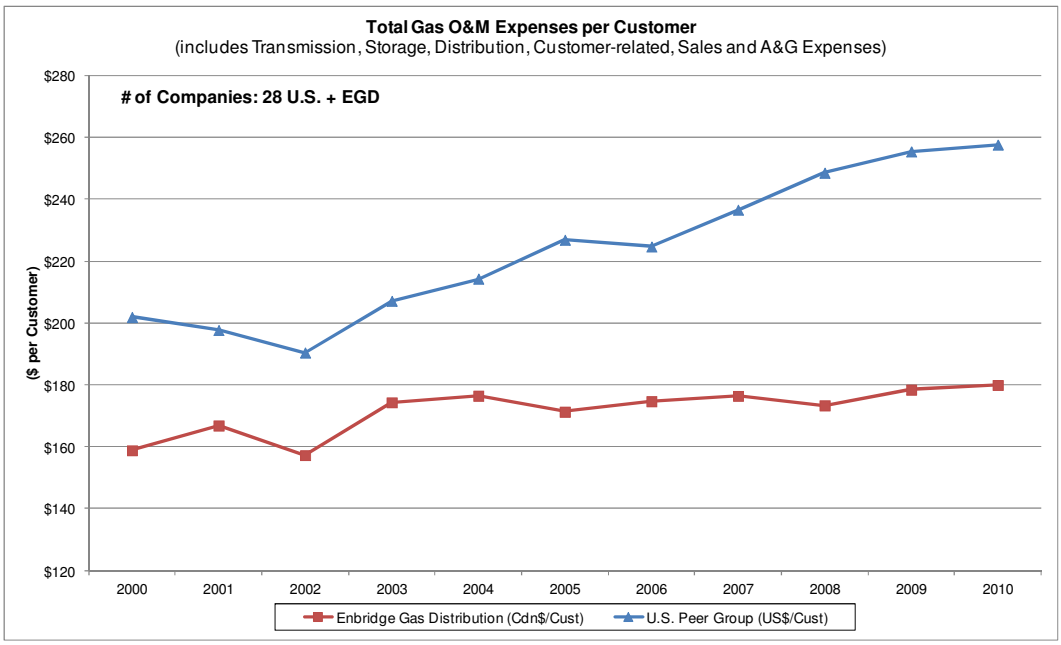

3. Gas O&M Expenses per Customer

The total 2009 and 2010 gas O&M expenses per customer for each utility are presented in the charts below. Enbridge was in the lowest quartile in terms of gas O&M expense per customer for both 2009 and 2010 and had the lowest gas O&M expense per customer compared to the Canadian peer group. This favorable cost profile is consistent with expected scale economies, and notable in light of Enbridge's residential concentration.



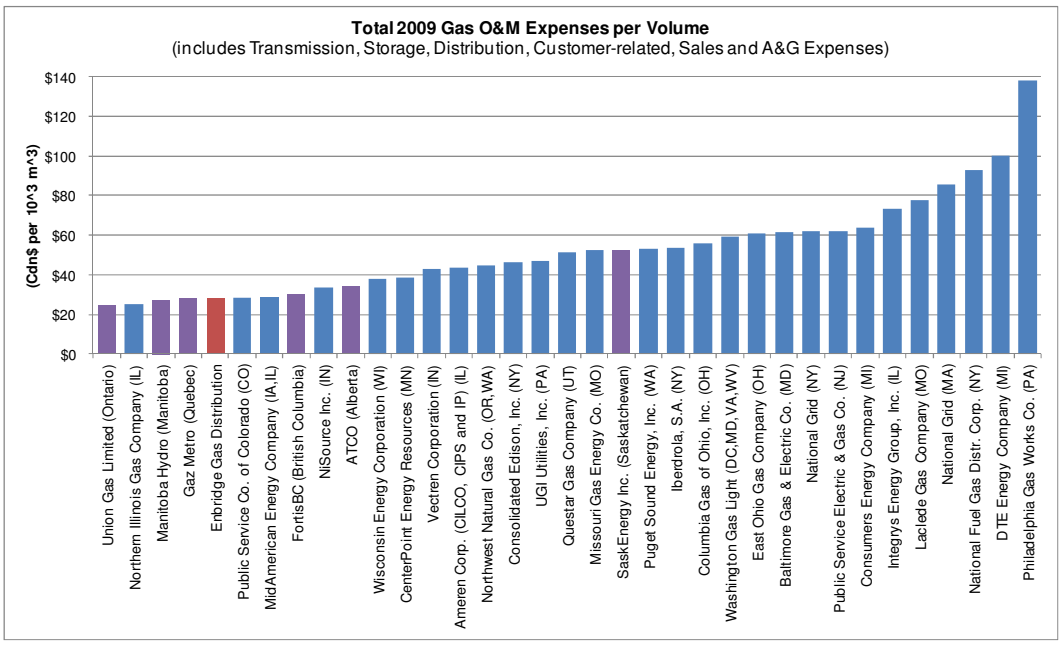



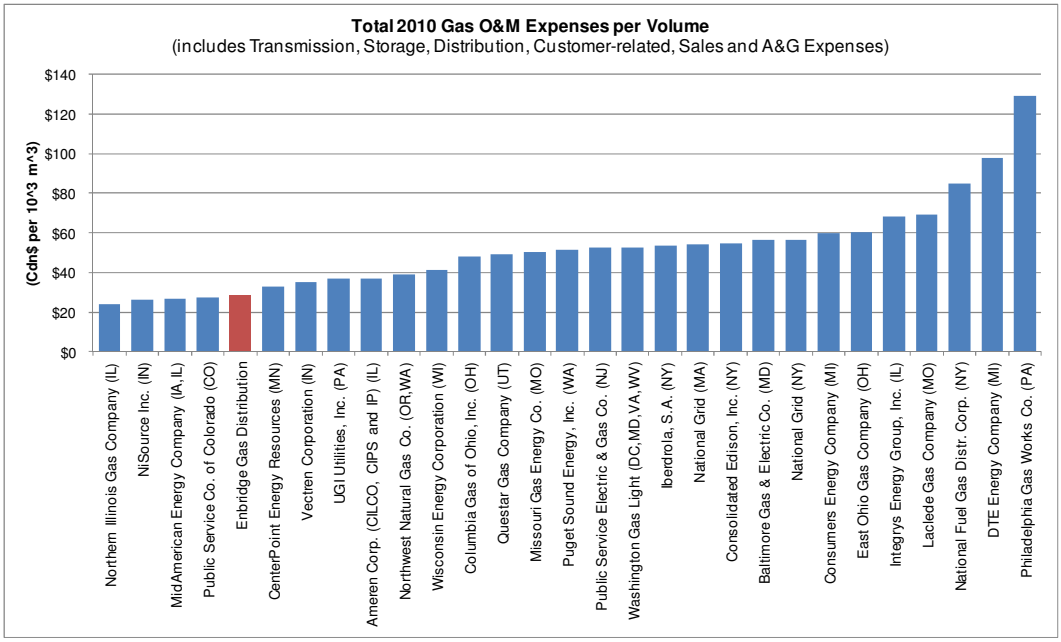

Over the 2003 to 2010 time period, Enbridge's O&M expenses per customer metric has remained steady at an average of approximately $176 per customer, whereas the U.S. peer group average has grown steadily since 2002.



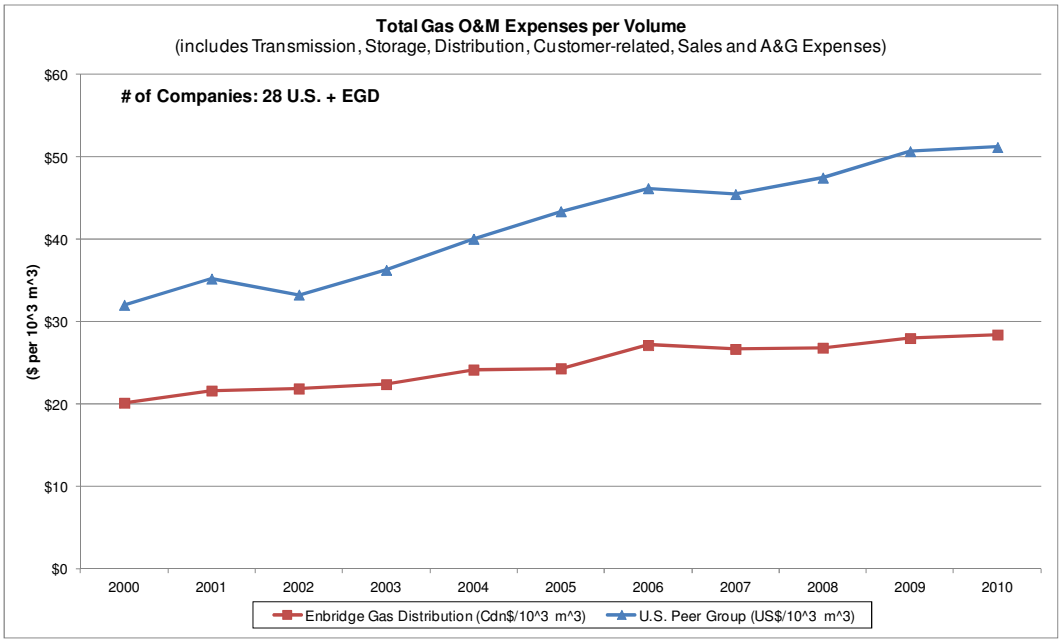

4. Gas O&M Expenses per Unit of Volume

The chart below depicts the total 2009 and 2010 gas O&M expenses per volume metric for each utility. As shown, Enbridge had the fifth lowest gas O&M expense per volume metric overall and was the median of the Canadian companies. The total gas O&M expense includes transmission, storage, distribution, customer-related, sales and A&G expenses.



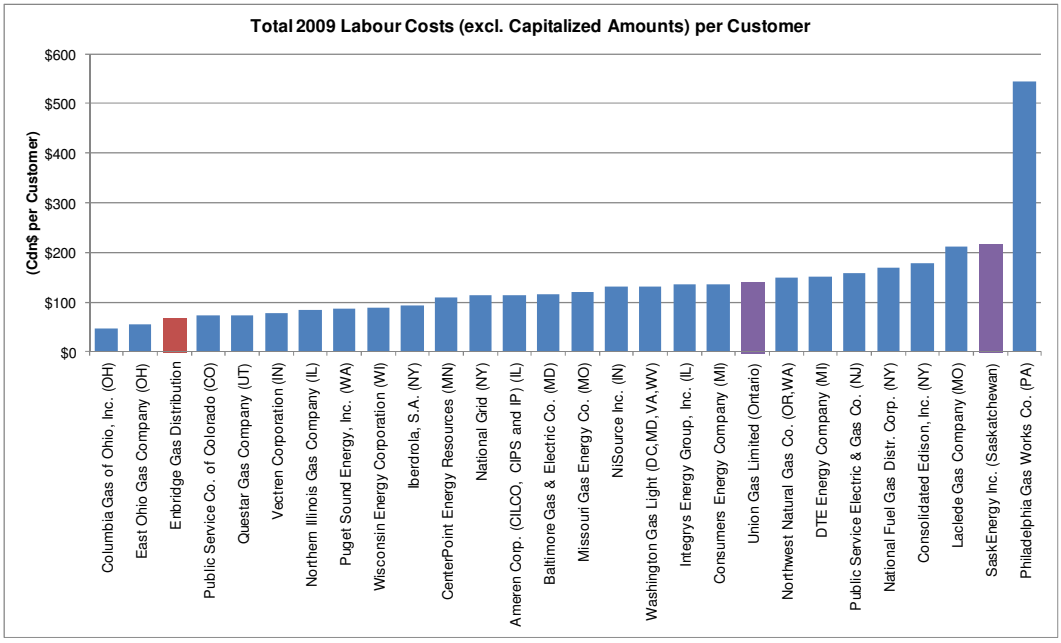


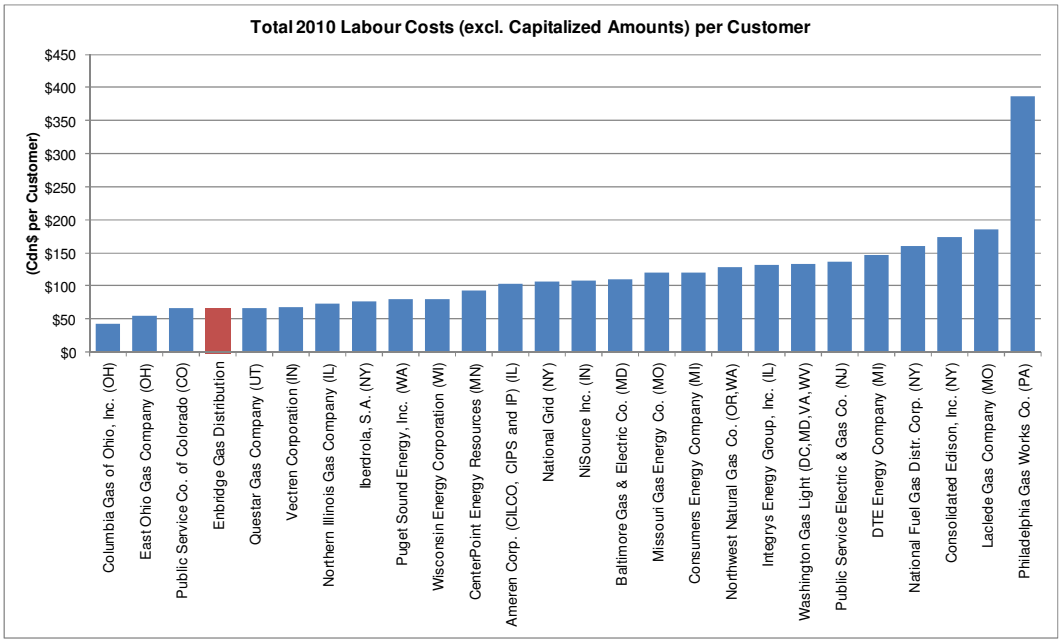

Both Enbridge and the U.S. peer group have experienced an upward trend in the gas O&M expenses per volume metric over the 2000 to 2010 time period, although the increase has been greater for the U.S. peer group. The general decline in volume/customer is partly responsible for this trend.



5. Labour Costs per Customer

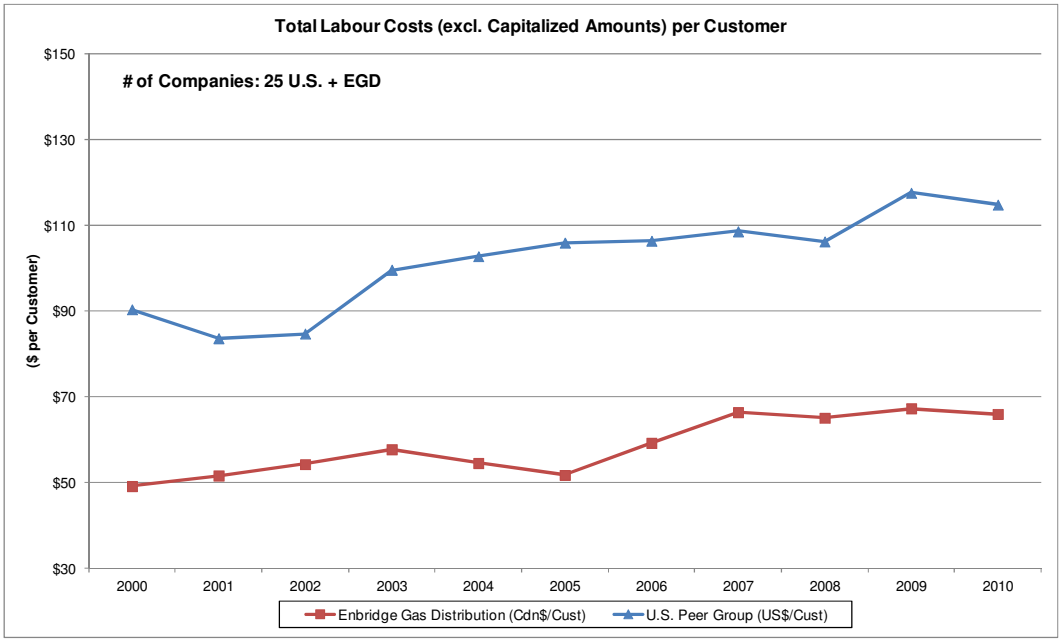
In terms of labour costs, Enbridge has the third lowest labour costs per customer metric in 2009 and the fourth lowest in 2010 compared to the peer group overall. Compared to the Canadian peer group, Enbridge has the lowest labour costs per customer as shown in the chart below.



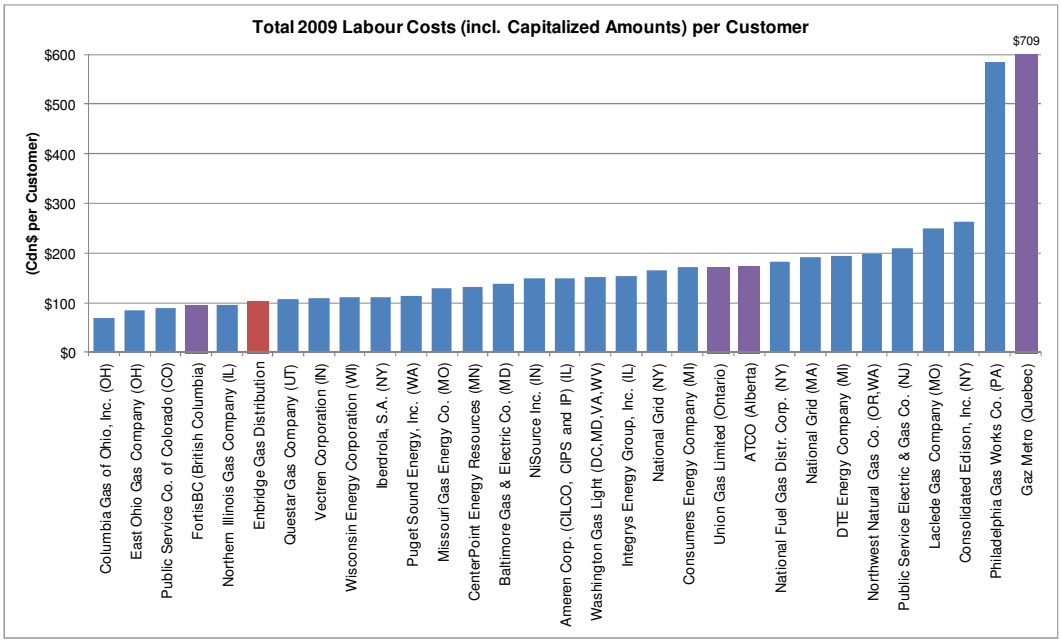



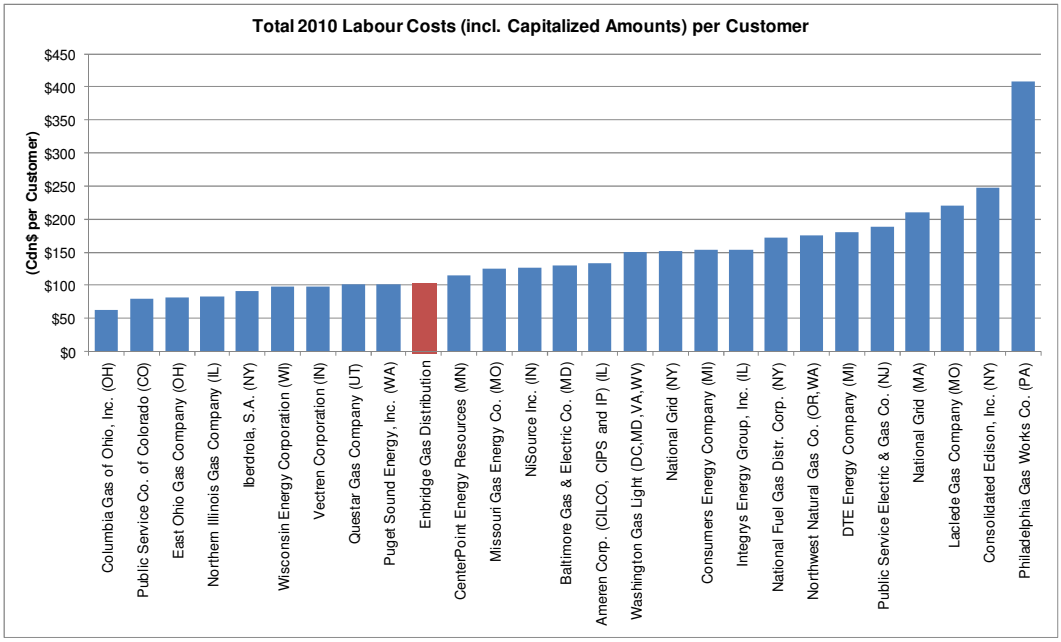

While both Enbridge and the U.S. peer group labor costs (excluding capitalized amounts) per customer have trended upward, Enbridge's increase has levelized over the 2007 to 2010 time period.

In 2010, both Enbridge and the U.S. peer group experienced a decline in total labour costs (excluding capitalized amounts) per customer.

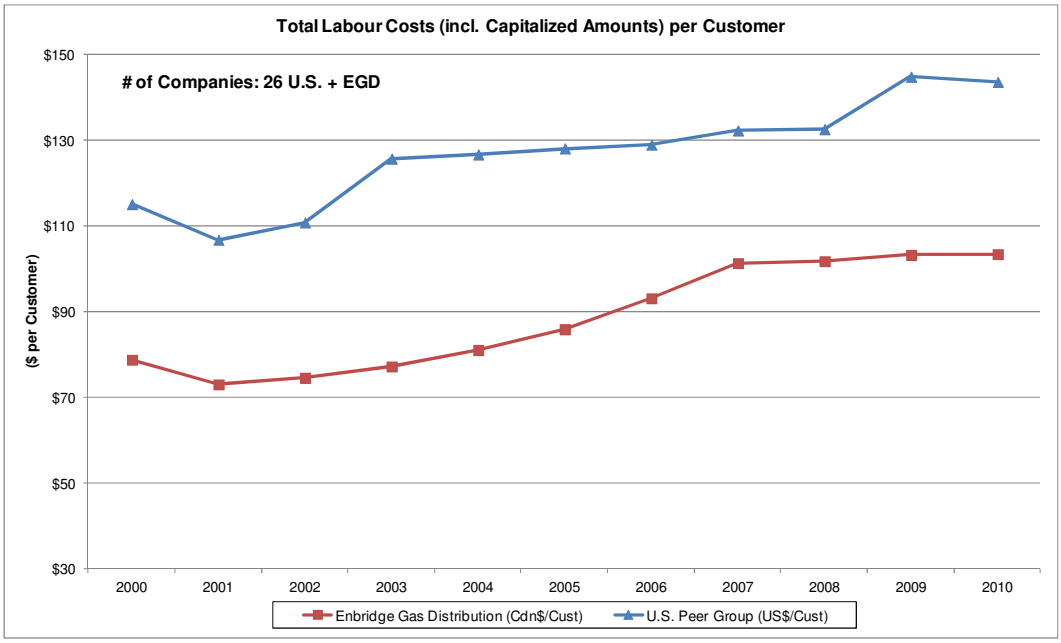



When including capitalized costs in the labour costs per customer metric, Enbridge ranks second lowest compared to the Canadian peer group and fifth lowest compared to the U.S. peer group in 2009. In 2010, Enbridge's labour costs per customer remained approximately $103 per customer; however, it ranks 10th lowest compared to the U.S. peer group. This shift is attributable to aforementioned exchange rate differential.





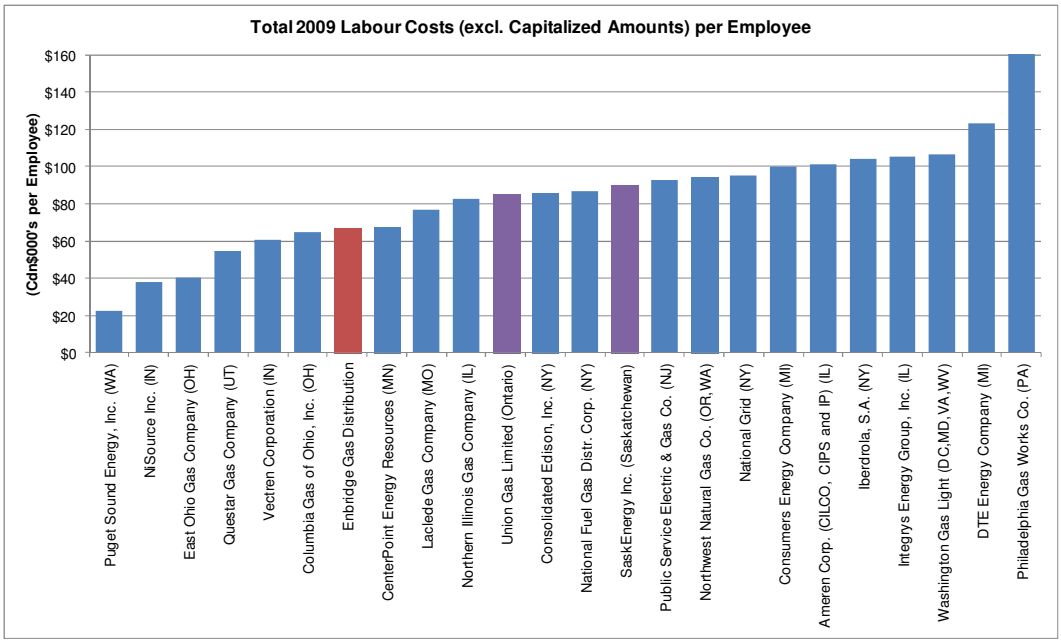

Both Enbridge and the U.S. peer group have experienced an increase in labour costs per customer over the 2000 to 2010 time period (including capitalized amounts). However, Enbridge's labour costs per customer have remained fairly constant over the most recent four years.



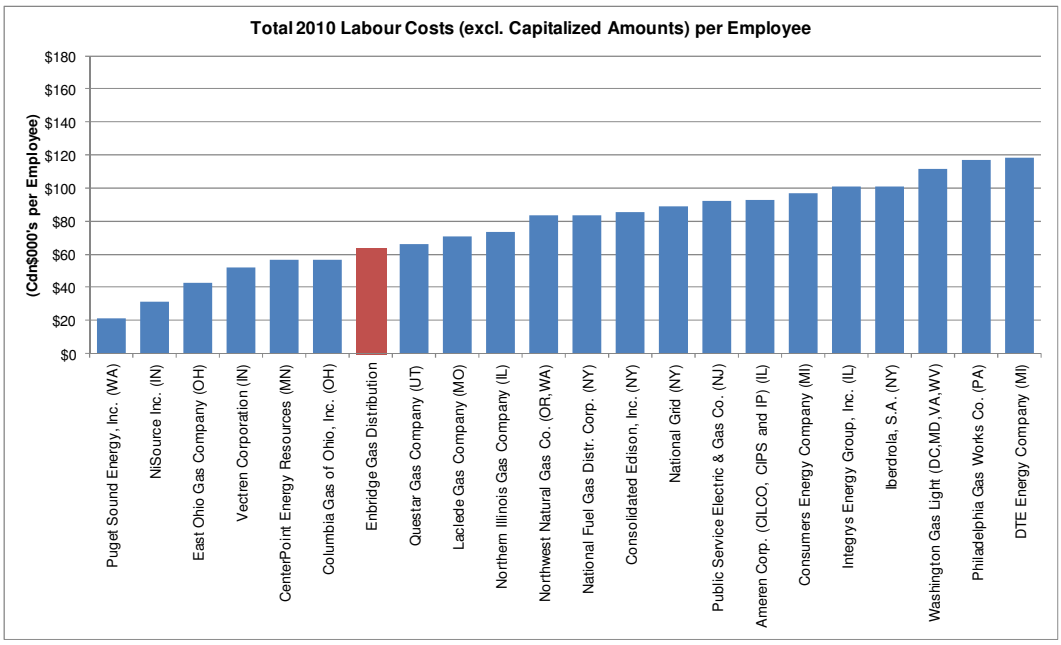

6. Labour Costs per Employee

In terms of labour costs per employee, Enbridge's labour cost of approximately $65,000 per employee in both 2009 and 2010 is lower than the average across the peer group, and ranks seventh

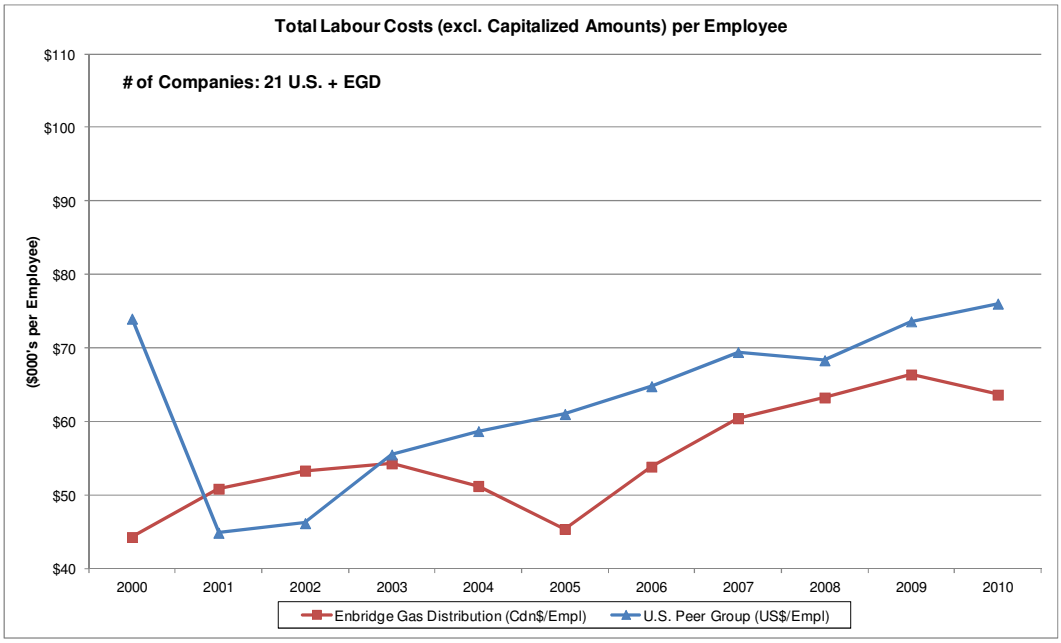
overall. This is somewhat unexpected given that Enbridge operates in two of the most expensive metropolitan areas in North America from a cost of living standpoint.[6] Higher labour costs are generally expected with higher cost of living.




6 According to Xpatulator.com, which provides cost of living information for 300 global locations: Toronto has an overall cost of living index which equates it with "high" cost of living locations. The overall cost of living index is comprised of the prices for defined quantities of the same goods and services across all 13 Basket Groups. Toronto is currently ranked 35 overall most expensive place in the world for expatriates to live, and the highest in North America, and Ottawa is ranked 107th out of 300 international locations. The cost of living is measured according to 13 Basket Groups as follows: Alcohol & Tobacco, Clothing, Communication, Education, Furniture & Appliance, Grocery, Household, Miscellaneous, Personal Care, Recreation and Restaurants, Meals Out and Hotel, and Transport.

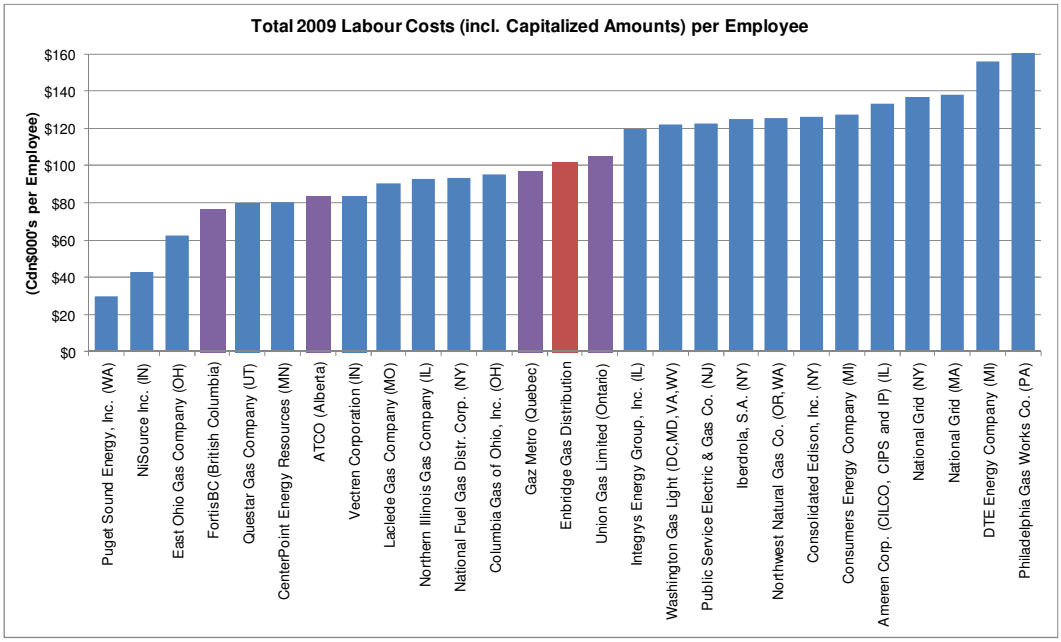


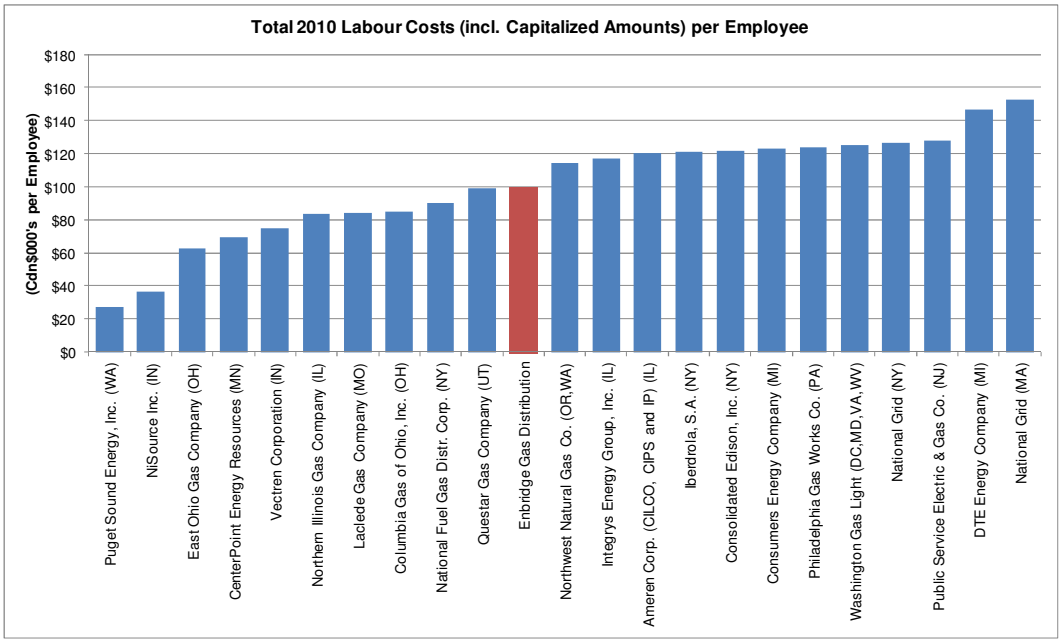

Labour costs per employee for both EGD and the U.S. peer group trended upward between 2005 and 2009. In 2010, the U.S. peer group continued the upward trend; however, Enbridge experienced a decrease in labour costs per employee.



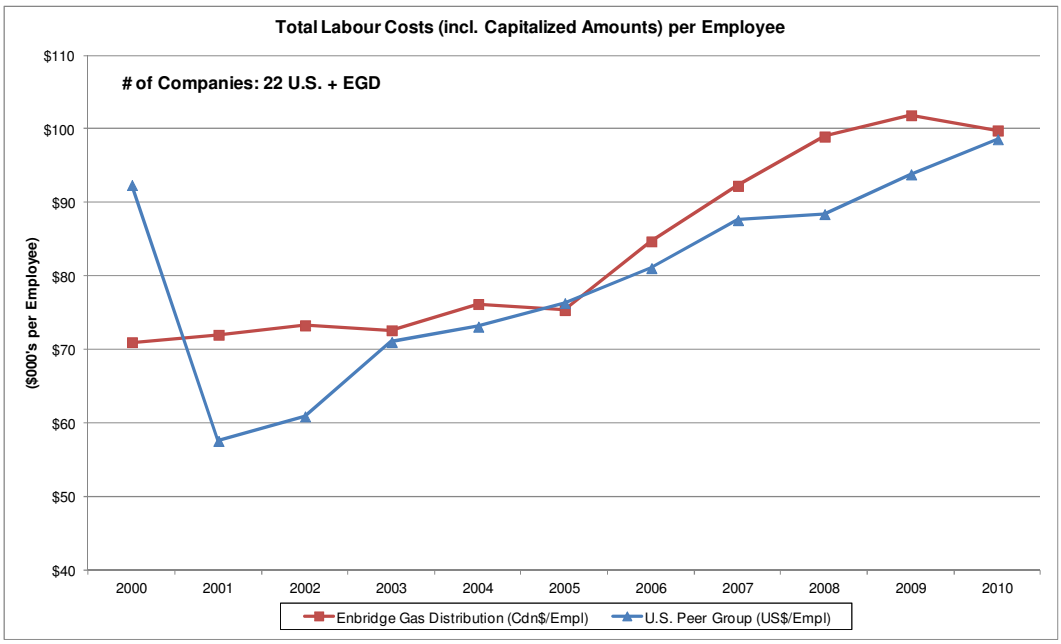

When including capitalized costs in the labour costs per employee metric, Enbridge ranks near the median of the peer group in both 2009 and 2010. Enbridge's labour cost per employee (including

capitalized labour) of approximately $100,000 is consistent with the labour costs per employee of Union Gas Limited and GazMetro, which are higher than Fortis BC and ATCO.



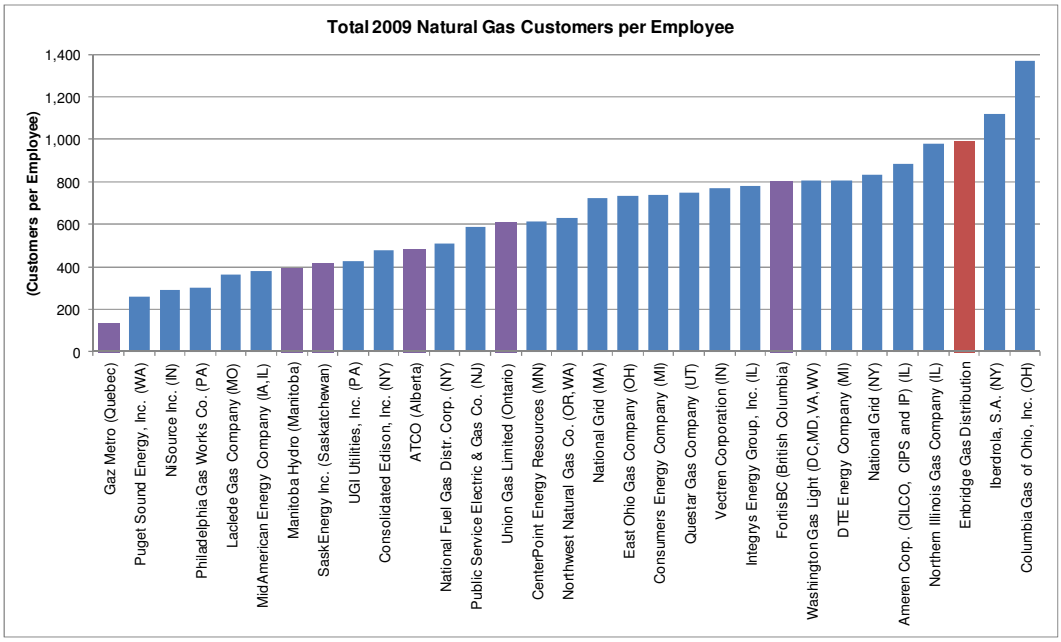



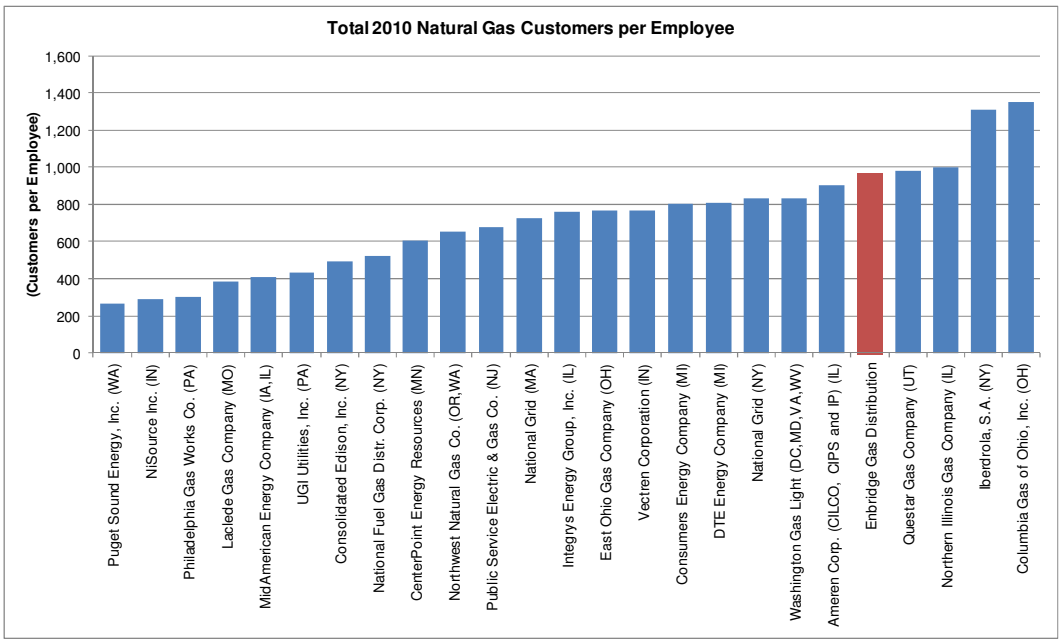

Over the 2001 to 2009 time period, both Enbridge and the U.S. peer group of 22 utilities have experienced an increase in labour costs per employee (including capitalized labour). In 2010, Enbridge experienced a decline in labour costs per employee, while the U.S. peer group continued to experience an upward trend.



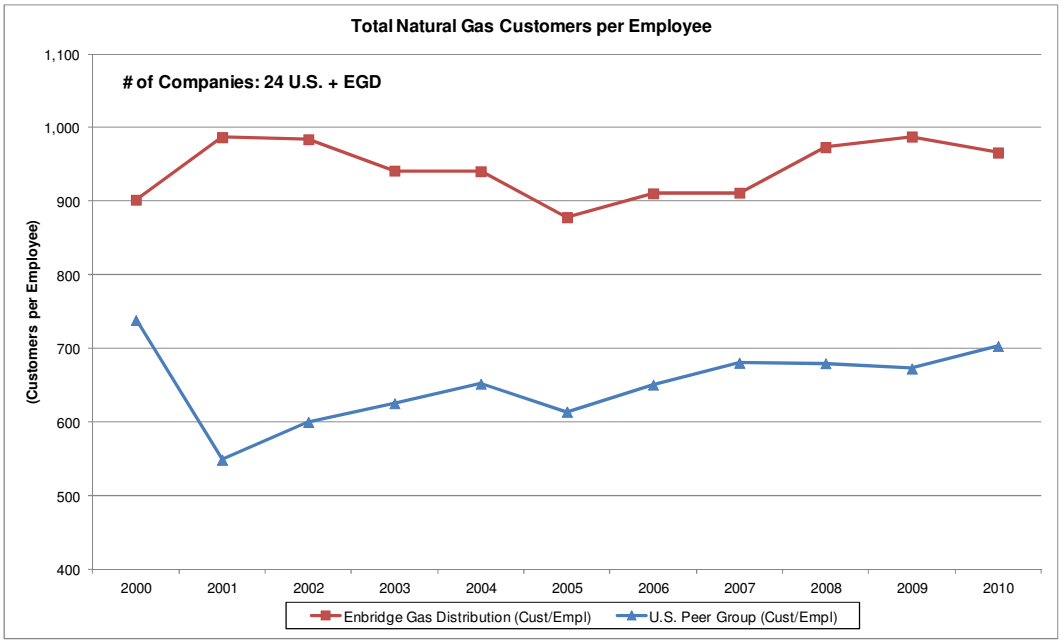

7. Customers per Employee

The chart below depicts the total 2009 natural gas customers per employee for each of the utilities. Enbridge has the highest level of customers per employee compared to the Canadian peer group, and is in the top quartile in both 2009 and 2010.






Over the 2000 to 2010 time period, Enbridge has maintained a high level of natural gas customers per employee as compared to the U.S. peer group average.




## IV. CONCLUSIONS

The benchmarking analysis contrasts Enbridge with a group of 28 U.S. natural gas utilities, comprised of 45 individual operating subsidiaries, and 6 Canadian natural gas utilities. The

benchmarking analysis in aggregate indicates that Enbridge is among the most efficient of its U.S. and Canadian peers.

In terms of comparative size and composition of the Company's service area:

- Enbridge has the 2nd highest customer count and 3rd highest throughput as compared to the U.S. utilities in the peer group, and has the highest customer count and the 2nd highest throughput compared to Canadian utilities, suggesting the potential for scale economies.
- The Company is, however, also in the top quartile in terms of residential customer percentage, which moderates scale impact in contrast to higher commercial and industrial concentration.
- Reflecting this customer profile, the Company ranks 8th of 35 in terms of average gas volume per customer in 2009 and 4$^{th}$ of 29 in 2010.
- Reflecting the relatively urban nature of EGD's service area, the Company ranks 7$^{th}$ in terms of customers and volumes per mile of distribution main.

In terms of comparative metrics for capital, operating and maintenance costs:

- The Company ranks 10$^{th}$ in terms of overall net plant invested per customer in 2009 and 5$^{th}$ overall in 2010, consistent with its relatively high residential customer profile. Net plant invested per customer has risen over the past decade for both EGD and the US peer group.
- Expressed on a volumetric basis, Enbridge ranks in the middle of all companies on a net plant per unit of system throughput. Due to declining use per customer, net invested plant per unit of throughput has risen more sharply for both EGD and the US peer group over the past decade.
- O&M costs per customer for Enbridge are the 3$^{rd}$ lowest overall in 2009 and 6$^{th}$ lowest overall in 2010, and the lowest of all Canadian companies. These costs have risen more slowly for EDG than for the peer group over the decade, and have remained relatively level for EGD during the 2007-2010 IR period measured.
- Expressed on a volumetric basis, Enbridge's O&M costs rank 5$^{th}$ overall, and at the median for the Canadian companies. EGD's O&M costs per unit of throughput have risen more slowly than the US peer group's over the past decade.
- Labour costs for Enbridge place the Company at 3$^{rd}$ (2009) or 4$^{th}$ (2010) overall on a per customer basis excluding capitalized costs and 6$^{th}$ (2009) or 10$^{th}$ (2010) including capitalized

costs, and better than all Canadian peers except Fortis BC. Enbridge's non-capitalized labour costs have risen more slowly than the US peer group in recent years.

- Expressed on a per employee basis, Enbridge's labour costs ranked 7th lowest overall excluding capitalized costs, and near the median including capitalized costs. The trend for Enbridge, considering capitalized amounts, has outpaced those of the US peer group in recent years.
- When considering customers served by utility workforce, Enbridge ranks 3rd highest in 2009 and 5th highest in 2010, and the highest of its Canadian peers. EGD has outdistanced its US peer group over the decade.

One would expect a utility of Enbridge's size and scale to be among the most efficient of its peers, even though its urban service area, residential customer concentration, and declining use per customer present cost challenges. One could argue that National Grid NY is most like Enbridge, with over 2 million customers and a relatively high customer concentration per kilometer of main, yet Enbridge ranks 3rd overall in O&M expenses per customer in 2009 while National Grid NY ranks 28th, and in 2010, Enbridge ranks 6th, while National Grid NY ranks 22nd. More consistent with expectations, the second largest company in terms of customers, Northern Illinois Gas, is also the second most efficient in terms of O&M costs per customer, just ahead of Enbridge which ranks 3rd in both categories.

On balance, the benchmarking analysis indicates that Enbridge is among the most efficient of its U.S. and Canadian peers in most categories measured. The exceptions are net plant per customer, net plant per unit of volume, and labour costs (including capitalized labour) per employee, where the Company is closer to or above the average. Examining trends over the 2000 – 2010 period measured, Enbridge has sustained or improved its position in relation to its peers, including during the most recent IR plan period.

the power to help you succeed.

*Report for*

Enbridge Gas Distribution

# Analytical Review of the September 2011 PEG-R Report

May 31, 2012

Contact: Steven A. Fenrick
1532 W. Broadway
Madison, WI 53713
Direct: 608-268-3549
Fax: 608-222-9378
Email: fenricks@powersystem.org
Web Site: www.powersystem.org

Power System Engineering, Inc.

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# 1 Executive Summary

On February 25, 2011, the Ontario Energy Board (Board) announced that it would conduct a preliminary assessment of the incentive regulation (IR) plans of two natural gas utilities: Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union). The scope of the Board's assessment was to examine the salient historical trends of the two utilities, prior to and during the incentive regulation period. As part of this assessment, the two utilities were compared to each other and to similar utilities. The comparisons involved areas such as economic performance, cost to consumers, shareholder value, capital investment, productivity, and efficiency. The goal of the assessment was to determine what impact the IR plans had in these areas.

## 1.1 The Pacific Economics Group Research Report

Pacific Economics Group Research, LLC (PEG-R) was retained by the Board to provide expert advice in the preliminary IR assessment. In September of 2011, the Board released a report authored by PEG-R entitled *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans* (PEG-R Report).

Power System Engineering, Inc. (PSE) was engaged by EGD to prepare the present report (PSE Review), which provides a preliminary review and appraisal of the key PEG-R Report findings, primarily as they pertain to EGD. The preliminary nature of the PSE Review's analysis is largely due to our current inability to review PEG-R's working papers, calculations, and clarify results as of yet. The Board has stated that the PEG-R Report will be filed in EGD's cost of service proceedings, and this will then provide an opportunity for a more complete analysis and evaluation of the PEG-R Report.

The PSE Review is not meant to investigate or make a judgment on the actual productivity trends of EGD or the industry. Rather, this PSE Review is meant to review the PEG-R Report's findings and provide improvements to PEG-R's methodology. PSE's improvements present the Board and other stakeholders with a more accurate depiction of EGD's performance during IR.

In the PSE Review, we will assume PEG-R performed its statistical calculations correctly and accurately, but we cannot yet independently verify the calculations. At the time of the discovery process, we will be able to evaluate the accuracy of the calculations made by PEG-R. Although we assume PEG-R's mechanical calculations are correct, we ultimately disagree with some of its assumptions and methodology.

In particular, we conclude that PEG-R's "backcasting" method of determining EGD's expected productivity trend during the IR period is incomplete. This results in PEG-R's mistaken conclusion that EGD has a fair amount of room to improve its total factor productivity. A more complete analysis, as presented in this PSE Review, shows convincing evidence that this is not the case.

## 1.2 Points of Agreement with the PEG-R Report

Our preliminary analysis of the PEG-R Report indicates that it includes a number of findings that PSE supports in its assessment of incentive regulation and EGD's performance within that framework. Our main objection to the PEG-R Report is discussed in Section 1.3 of this PSE Review.

The findings which PSE supports contained within the PEG-R Report include:

- EGD's positive response to incentive regulation, as demonstrated by its effective cost controls and higher productivity and efficiency;
- EGD's declining rates during the IR period, which have benefited customers; and
- EGD's ability to achieve strong cost containment despite rapidly growing input prices, particularly relative to the Canadian GDP-IPI during the examined incentive regulation period.[1]

These findings by PEG-R show that EGD has responded to IR in a manner that has benefitted its customers. Higher productivity and efficiency ultimately lead to lower gas delivery rates. The economic benefit of lower rates goes without saying. However, this is a very atypical outcome for most gas distributors in North America. As PEG-R correctly points out, the gains in efficiency, productivity, and the decline in prices occurred during a time when EGD faced input prices that were growing faster than the Canadian GDP-IPI.

Therefore, we believe much of the PEG-R Report to be accurate. However, our analysis indicates that PEG-R's methodology of estimating EGD's "expected" total factor productivity significantly inflates PEG-R's estimate of this value. We summarize the flaws in the PEG-R methodology in the following section.

## 1.3 Deficiency in the PEG-R Report: TFP Trend Methodology

PSE substantially agrees with PEG-R on the bullet points listed in the previous section. However, PEG-R states one conclusion with which we must disagree: the conclusion that EGD has room to improve its productivity beyond its current level. Our analysis shows that PEG-R's assessment of EGD's expected TFP trend is incorrectly inflated, due to their selected methodology.

PEG-R makes the conclusion that EGD has room to improve its TFP by comparing EGD's measured TFP trend of 0.93% (during the examined incentive regulation period of 2008-2010) to PEG-R's calculated TFP "backcast" of 1.25% during that same period. PSE's Review will demonstrate that the PEG-R method used to determine the TFP prediction of 1.25% can be improved to provide a more accurate and appropriate depiction of EGD's expected TFP.

[1] PEG-R's conclusions are summarized in Section 1.2 of the PEG-R Report ("Summary of Results," pp. 3-12).

A "backcast" is defined by PEG-R as follows:

> A "backcast" is analogous to a forecast except it generates counterfactual scenarios for the past rather than hypothetical scenarios for the future. In this instance, our objective was to predict what the TFP growth of a typical North American gas distributor would have been if it had operated under the business conditions of EGD and Union, respectively, in the 2005 – 2010 period. We define a typical gas distributor as one that operates with average efficiency.[2]

Thus, a backcast as so defined is similar to a benchmarking study: PEG-R is comparing EGD's measured TFP growth to that of a "typical" gas distributor with "average efficiency." PEG-R calculates EGD's TFP trend for 2008-2010 to be 0.93%, and then compares this measured trend to the expected (backcast) trend, which they find to be 1.25%.[3]

Based on these results, PEG-R claims that EGD has room to increase its TFP trend, and that a typical gas distributor facing EGD's circumstances would have had TFP growth that is 0.32% higher than EGD achieved during that period. This PSE Review shows that PEG-R's claim is mistaken, because it uses an incomplete and mis-specified TFP backcast methodology.

## 1.4 Improving PEG-R's Methodology

In this PSE Review, we recommend three improvements to the PEG-R TFP backcast methodology. We also provide preliminary estimates of the impact of these improvements on the expected TFP of EGD during the examined IR timeframe. The improvements appear to lower EGD's expected TFP trend during 2008-2010 by over 300 basis points. We find that a more accurate and appropriate approach indicates that EGD's expected TFP during the IR period is not 1.25% per year, as PEG-R claimed, but rather -1.80% per year.

The three suggested improvements on the expected TFP trend are:

1. Revert to PEG-R's 2007 methodology for econometric TFP backcasts. The 2011 PEG-R Report altered PEG-R's prior methodology to include the expected productivity impacts of business condition variables. PEG-R presented evidence in their 2007 report that this method will distort expected TFP measures; however, they decided to include these impacts in their current methodology. PSE conducted further research that substantiates PEG-R's 2007 finding that the inclusion of long-run business condition variable impacts on short-run TFP projections is not warranted and leads to distorted results. We suggest reverting to PEG-R's original methodology of not including business condition impacts in the calculation of expected TFP trends.

[2] PEG-R Report, Section 6.2.1.1 (p. 94).

[3] PSE is not endorsing the measured TFP growth of 0.93% for EGD. However, we are assuming in the PSE Review that PEG-R calculated this accurately. During the discovery process, we will be able to make more robust statements regarding this number. One obvious item that should be further explored is that PEG-R appears to exclude gas delivery volumes in their construction of TFP trends. Typical productivity research includes volumes as an output in the measurement of TFP trends. The rationale for PEG-R departing from this standard practice should be explored further.

2. Estimate the time trend variable using a more applicable time period. PEG-R is estimating the expected 2005-2010 TFP performance of EGD using model results that are derived from a dataset that begins in 1999 and ends in 2009. While PSE recognizes the requirement to have sufficient observations in the estimation of an econometric cost model, we put forth a model that is very similar to the PEG-R model but based on 2002-2009 data. This provides a more applicable time period in which to evaluate the performance of EGD during 2005-2010.

3. Beginning level cost efficiency should be accounted for when calculating expected TFP trends. Concentric's January 2012 *Benchmarking Study* provides strong evidence of EGD's top quartile O&M cost efficiency relative to its industry peers. PSE found statistically significant evidence within the U.S. natural gas distribution industry that the beginning period O&M cost efficiency influences future short-run TFP trends. Formulating an expectation of TFP trends is incomplete without incorporating the beginning level cost efficiency of the examined company.

## 1.5 Examining the Upward Bias Inherent in the PEG-R Methodology and Comparison to PSE Suggested Improvements

PSE attempted to replicate the TFP trends for the PEG-R industry sample, to compare EGD's TFP (as measured by PEG-R) to the industry as a whole. Without access to the actual data values and exact methods used by PEG-R, this replication is only approximate. The replication process can be finalized, if desired, after the discovery process is completed. Our preliminary findings are that in recent years, the industry average and median TFP trends have been negative. PSE's preliminary assessment is that, on average, the measured industry TFP (using the PEG-R U.S. sampled utilities and calculation methods) *declined* by about 0.77% per year from 2007-2009. The industry median decline was 1.43%. Figure 1-1 compares these negative U.S. industry trends to EGD's measured performance of positive TFP growth of 0.93%.

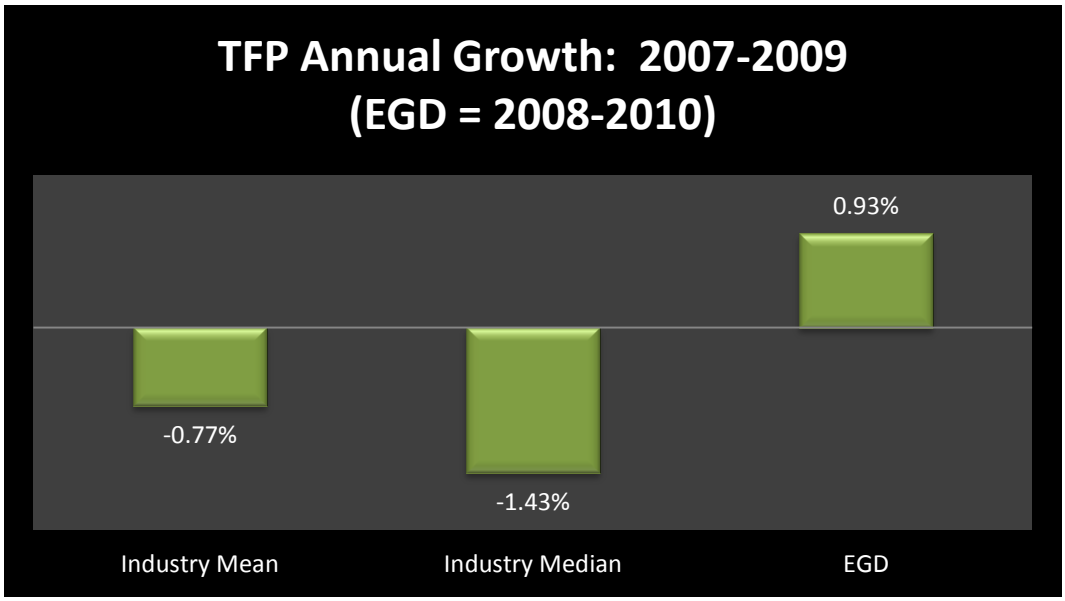



**Figure 1-1 Measured TFP Growth: Industry Mean/Median vs. EGD**

Figure 1-1 shows the annual TFP growth for the industry mean, the industry median, and EGD over a three-year period.[4] We should reiterate that the PEG-R method used to measure EGD's TFP growth of 0.93% (and the industry TFPs) is not disputed here, at least in our preliminary review. What we dispute is PEG-R's method for calculating the "backcasted" (or "expected") TFP.

We illustrate the bias inherent within the PEG-R backcast methodology in Figure 1-2. That figure provides an estimate of the *measured* TFP trends of the PEG-R United States sample, and compares it to what the industry's *estimated* trend would be using PEG-R's backcast methodology. The figure also presents PSE's calculation of the industry trend using our improved methodology.

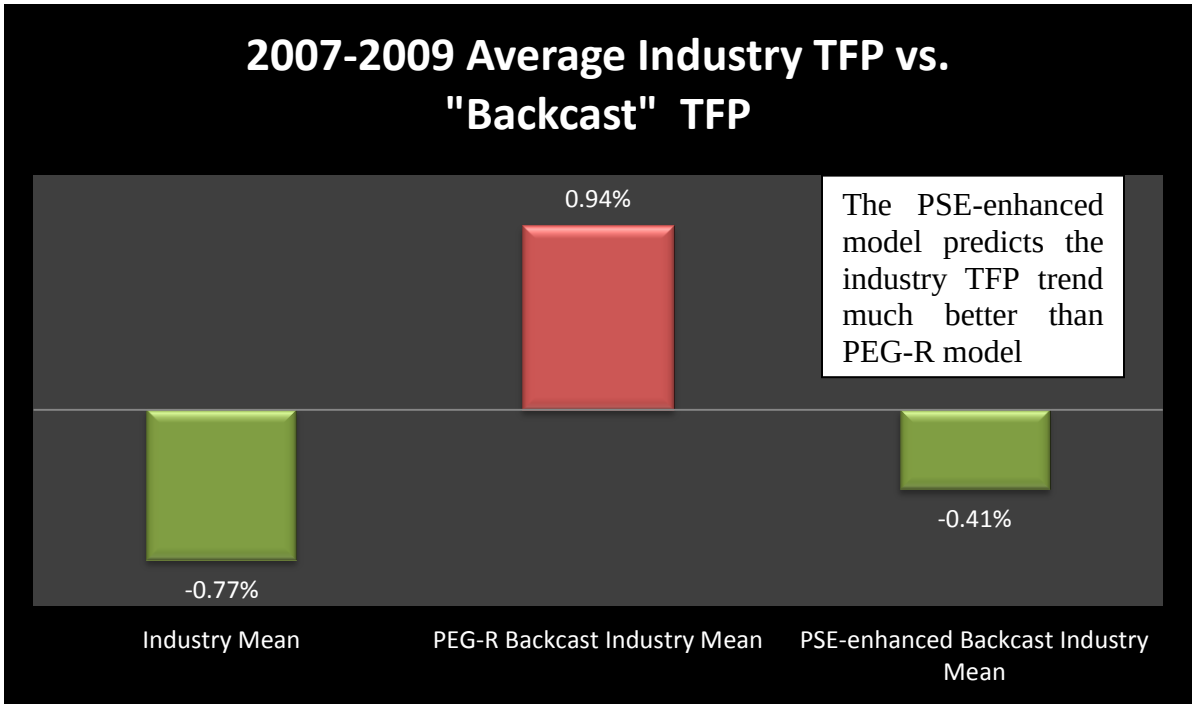
As mentioned above, the measured average industry TFP *declined* by about 0.77% per year from 2007-2009. However, the PEG-R backcast methodology indicates the industry "should" have had an average TFP *growth* of 0.94% per year. This large mismatch between PEG-R's backcasted TFP trends and the measured TFP trends provides strong evidence for an upward bias in PEG-R's current TFP backcast methodology.

Examining how well a model predicts sample outcomes is key to determining its accuracy and validity. In this report we provide evidence that the PEG-R methodology gives TFP predictions which are demonstrably too large. However, PSE's enhancements to the model increase its

[4] In the PEG-R Report, it appears that the authors are calculating growth rates for the 2008-2010 time period using the average growth rate beginning in year 2007. They are averaging the growth from 2007 to 2008, 2008 to 2009, and then 2009 to 2010, and classifying this as the 2008-2010 average annual growth rate. While PEG-R's label of "2008-2010" is somewhat unorthodox (it would typically be called a 2007-2010 growth rate), PSE uses this same labeling convention in this document to remain consistent with the PEG-R Report and minimize confusion. For the industry numbers, the time period of 2007-2009 is used, because as of the time of this PSE Review, the 2010 industry numbers are not yet available.

accuracy. In other words, the PSE-enhanced model predicts the actual observations much more accurately than the PEG-R model. This is illustrated in Figure 1-2 below.

**Figure 1-2 Industry Mean TFP: Measured vs. PEG-R Backcasted vs. PSE Backcasted**




Similar increases in accuracy are achieved when the PSE enhancements are applied to EGD. PEG-R estimated that EGD's backcast trend was 1.25% per year. Our initial assessment, using PEG-R's backcast framework combined with PSE's enhancements, indicates that a more appropriate expected TFP growth trend for EGD during 2008-2010 would be around -1.80% per year.

## 1.6 Implications for the X-Factor

EGD's annual TFP growth of 0.93% per year (as measured by PEG-R) is substantially above the -1.80% expected mark (as measured with PSE's improvements)—2.73% per year above. PEG-R's conclusion that EGD has scope to increase this trend in the future does not appear to be accurate. In fact, given the strong productivity results of the company in recent years relative to industry expectations, it is likely that the opposite is true: we would expect EGD's TFP to fall back closer to the "expected" value in upcoming years.

**Table 1-1 EGD's Measured vs. Expected TFP**

| IR Measured TFP Growth | Expected Backcast TFP (using PSE improvements) | Difference |
|---|---|---|
| 0.93% | -1.80% | **2.73%** |

PSE used the revised expected TFP trend and other information to provide a historical examination of the X-Factor during the 2008-2010 period.[5] This "Backcast" X-Factor is -2.00% (as calculated by using the PSE-improved backcast TFP method). We then compared this to the "actual" X-factor for EGD as realized in its IR plan (0.72%, as measured by PEG-R). Our preliminary findings are that EGD's measured X-Factor was over 250 basis points greater than the expected X-Factor, given all historical factors such as expected TFP, observed output growth, and observed input price inflation. Table 1-1 summarizes the difference.

**Table 1-2 EGD's Measured vs. Expected X-Factor**

| IR Measured X-Factor | Expected Backcast X-Factor (using PSE improvements) | Difference |
|---|---|---|
| 0.72% | -2.00% | **2.72%** |

## 1.7 Conclusion

PSE is supportive of the Board's initiative to examine each gas utility's performance under IR. This is a helpful exercise to assure that utilities are offering strong value to stakeholders. We also agree with PEG-R's approach of emphasizing the productivity trends of the gas utilities and comparing them to industry standards. This approach is informative, because ultimately productivity trends will influence utility cost levels and revenue requirements. Thus the PEG-R focus on the TFP trends is the correct general approach. This PSE Review has provided specific improvements that make the general approach more accurate.

Our preliminary research in this PSE Review indicates that EGD's productivity trend was well above that of the industry and therefore provided strong value to stakeholders. This high productivity trend has provided consumers with lower rates than would have normally been the case.

[5] Under incentive regulation, the allowed rate of change in the price of natural gas is generally restricted by the growth in an inflation factor minus a productivity offset and a stretch factor. The productivity offset is often called an "X-Factor," and can include other offsets, such as an industry input price differential. See Section 5 of this Review for more details.

# 2 Introduction to the PEG-R Methodology

On February 25, 2011, the Board announced that it would conduct a preliminary assessment of the incentive regulation plans of EGD and Union. The scope of this assessment was to examine the salient historical trends of the two natural gas utilities both prior to and during the incentive regulation period. As part of this effort, utility results were compared to each other and to similar utilities. PEG-R was retained by the Board to provide expert advice in the preliminary incentive regulation assessment. In September 2011, the Board released PEG-R's Report.

## 2.1 PEG-R's Backcast Model

As stated in the Executive Summary, this PSE Review provides a preliminary review and appraisal of the key PEG-R Report findings, primarily as they pertain to EGD. In particular, we will analyze and suggest enhancements to PEG-R's benchmark (backcast) TFP trends. However, in making these suggested research enhancements to PEG-R's modeling approach; PSE is not implicitly approving that paradigm.[6]

For example, PEG-R employs an econometric model to develop TFP "backcasts," which are similar to benchmarks. Backcasts estimate what the TFP "should" have been for a previous time period, given the relevant factors. PEG-R uses this econometrically-derived TFP prediction as an estimate of EGD's "expected" past TFP, and compares it to EGD's measured past TFP trend. PSE has a number of suggested enhancements to improve PEG-R's calculation of the TFP backcast, but we are not convinced the econometric backcast method is the best way to calculate expected annual TFP growth.

On the contrary, we do not see the necessity of deviating from the more conventional approach of using an industry-wide TFP trend as the basis for determining the proper future TFP trend for EGD. (Alternatively, a suitably large peer group could be used as the basis.) This is especially true during the examined incentive regulation time period of 2008-2010, when EGD's customer growth has moved much closer to U.S. industry standards.[7]

In fact, in Section 3.4, PSE provides strong evidence for the merits of using large peer group TFP trends versus PEG-R's TFP backcast methodology. This evidence shows the potential bias in PEG-R's research by comparing the average TFP trends of their sample (as measured) with the average TFP backcast (predicted) trends of their sample. This analysis showed that PEG-R's methodology expected, on average, TFP growth of 0.94% per year, whereas the average sample

[6] Here we note another feature of PEG-R's approach to calculating TFP trends. The PEG-R authors derive an output index using cost elasticity weights, and customers and pipeline length as the relevant industry outputs. In other research on TFP trends throughout the industry, revenue weights serve as the basis for creating an output index, and these typically have the number of customers and gas delivery throughput as their outputs. A customer growth adjustment is necessary when using revenue-weighted TFP trends to calculate an X-factor in EGD's revenue per customer incentive regulation formula.

[7] As stated above, in the PEG-R Report it appears that the authors are calculating growth rates for the 2008-2010 time period using the average growth rate beginning in year 2007. They are averaging the growth from 2007 to 2008, 2008 to 2009, and then 2009 to 2010 and classifying this as the 2008-2010 average annual growth rate. While this label is somewhat unorthodox (this would typically be called a 2007-2010 growth rate), PSE uses this same labeling convention in this document to remain consistent with the PEG-R Report and minimize confusion.

measured TFP trend *declined* by 0.77% per year from 2007 to 2009. This amounts to an upward bias in their methodology of 1.71%.

## 2.2 PEG-R's Conclusions Regarding EGD's Response to IR

PEG-R showed that both EGD and Union have responded positively to incentive regulation. PEG-R states on page 121 of its report that:

> [PEG-R's] analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements.

The evidence used by PEG-R to substantiate this claim is based on an examination of each utility's TFP trend and a comparison of this trend to what PEG-R calls a "TFP backcast," based on the performance and trends of the U.S. gas utility industry as a whole (or of a group of utilities identified by PEG-R as a peer group).

The positive responses by EGD and Union provided tangible benefits to Ontario's gas customers. PEG-R notes that EGD's gas rates (as paid by its customers) declined over the examined incentive regulation period of 2008-2010. This is noteworthy, because even while EGD's input prices and prices in general were trending upward, the gas delivery prices charged were declining for EGD's customers.

PEG-R shows in Table 9 of its report that the input prices facing EGD during the 2008-2010 period increased by an annual rate of 2.11%. The Canadian GDP-IPI increased by 1.66% during this same time period. According to PEG-R, EGD's input prices rose about 0.45% faster than prices for the economy at large, while EGD's gas delivery rates still fell by 0.32%. On page 73 of its report, PEG-R states that "… input price inflation for EGD and Union outstripped the growth in both the GDP-IPI inflation factor and the Companies' gas delivery prices."

PEG-R correctly points out on page 63 that this input price differential of 0.45% between EGD's input price inflation and the increase in the GDP-IPI, which was used in the formulation of the incentive regulation plan, implies that customers received a "windfall gain at the expense of shareholders." Proper incentive regulation mechanics would suggest that this "inflation differential" be added to the GDP-IPI growth rate (or be subtracted from the X-factor) to allow the inflation factor to more accurately track the input price trends faced by EGD. In Section 5 of the PSE Review, we take the step of examining the X-Factor in light of this information.

## 2.3 The PSE Review

PEG-R notes that the differential between the EGD observed TFP trend and the predicted trend narrowed during the IR period. They also make the claim that "our analysis implies that there is scope for EGD to boost its TFP." Sections 3 and 4 of this Review evaluate the PEG-R statement that EGD's TFP growth was below the expected level.[8]

[8] Again, our evaluation will necessarily be more qualitative in nature and not make definitive conclusions on the effects of a given methodological alternative, due to our current inability to fully examine PEG-R's research.

Our preliminary analysis finds that EGD substantially outperformed its expected TFP trend during the examined IR period. This refutes PEG-R's conclusion that EGD has scope to increase its TFP trend beyond the observed 0.93%. In other words, PEG-R concluded that EGD underperformed its expected TFP trend in recent years and so has room to improve. In fact, the opposite is likely to be true. Given the rapid TFP growth of EGD in recent years relative to industry standards, we would expect EGD to move closer to industry norms in future years.

In Section 5 of this Review, PSE calculates what an appropriate X-Factor would have been during 2007-2010 given the now available historical growth rates of output and input prices, combined with our enhanced assessment of expected TFP growth. This X-Factor equals -2.00%. This is relative to the measured implicit X-Factor that EGD faced during this timeframe of 0.72% (as calculated by PEG-R on page 46 of their report).

# 3 Analysis of PEG-R's TFP "Backcasts"

PEG-R uses econometrically informed backcasts to compare EGD's measured TFP growth with PEG-R's "expected" TFP growth. Table 23 of the PEG-R Report presents results of the comparison. The expected TFP growth is based on an econometrically estimated total cost function.

The econometric sample included 34 U.S. gas distribution utilities over a sample period of 1999-2009. On the basis of these results, PEG-R states that EGD's TFP performance improved during the incentive regulation period. However, they also make the claim that there is room for improving this trend, based on the assumption that the backcast TFP growth was higher than EGD's measured growth. (This Review shows PEG-R's projected backcast TFP growth to be mistaken.) A summary of PEG-R's Table 23 as it pertains to EGD is provided in Table 3-1 below.

**Table 3-1 EGD's Measured vs. Expected TFP (PEG-R Report)**

| Time Period | Expected TFP Growth | Measured TFP Growth | Difference | Conclusion Based on Results in Table |
|---|---|---|---|---|
| 2005-2007 | 1.92% | 1.29% | -0.63% | EGD has room to improve |
| 2008-2010 | 1.25% | 0.93% | -0.32% | EGD has room to improve |

The expected TFP growth uses the econometric estimates found in Table 20 of the PEG-R Report. These estimates are then used to predict the average annual cost growth of EGD over the 2005-2007 and 2008-2010 time periods, given EGD's change in their outputs and business conditions over those same time periods. The cost growth estimates are found in Table 21. Table 22 of the PEG-R Report then takes the predicted cost growth estimates and translates them into predicted TFP trends by subtracting the input price index from the estimated cost growth, and adding in the change in the output quantity index.

This method of projecting TFP, while appearing to be mathematically accurate, is more cumbersome and more difficult to evaluate then the more straightforward TFP decomposition method presented by Pacific Economics Group in its November 2007 report, *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*.[9] The "2007 method" was also published by PEG-R personnel in a 2009 article in the academic journal of *Review of Network Economics.*[10]

[9] The authors of the November 2007 report included the president of PEG-R, Mark Lowry, and a co-author of the PEG-R Report, Dave Hovde. The other two authors of the November 2007 report, Steve Fenrick and Lullit Getachew, now are employed by PSE and are the authors of this review.

[10] Lowry, Mark N. and Lullit Getachew (2009). "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," *Review of Network Economics*. Volume 8, Issue 4 – December 2009. The two co-

Given PSE's current inability to obtain comments on a number of questions we have on the new calculations in the PEG-R Report, we decided to use PEG-R's 2007 method of projecting TFP trends when evaluating predicted TFP trend for EGD. This provides consistency of calculations and resolves a number of our questions on their new approach. The established TFP decomposition method yields very similar results to PEG-R's new method.

In the following three sections (3.1, 3.2, 3.3), we use the 2007 method to derive expected TFP trends for EGD for the 2008-2010 period. We then present the estimated impacts of three suggested enhancements on the expected EGD TFP trend for 2008-2010. Since the 2007 method and PEG-R's method as stated in the PEG-R Report appear to provide similar results, these three enhancements and their impact on expected TFP trend estimates are applicable to both methods of calculating expected TFP trends. In this Review, PSE uses the previously designed 2007 method to calculate expected TFP, due to our inability to request further information from PEG-R on its new method, and due to the fact that the new method is less straightforward than the 2007 method.

We now turn to the three enhancements that would improve the PEG-R methodology, thus producing a more accurate TFP expectation for EGD.

## 3.1 Enhancement #1: Eliminate Long-Run Impacts of Business Condition Variables in Short-Run Research

Table 3-2 below presents the TFP decomposition method presented in the November 2007 report, updated to reflect the new results and econometric model found in the PEG-R Report. The 2007 report did not include in its TFP calculation the influence of what PEG-R calls "business condition variables." PEG-R found two such variables to be potentially relevant: the percentage of mains that are non-cast iron and bare steel, and the number of electric customers.[11] However, PEG-R did not include business condition variables in the 2007 report's calculation of expected TFP trends, as those variables tend to influence TFP trends over the long term rather than the short term.

In the PEG-R Report of 2011, however, when evaluating EGD's 2008-2010 expected TFP, PEG-R has deviated from its prior practice, and included the long-term influence of business condition variables, despite the fact that an extremely short-term trend (TFP) is being evaluated. The inclusion of business condition variables in the 2011 PEG-R Report skews the benchmark TFP trend of EGD (and for the entire sample, as we will show in Section 3.4), and is counter to past statements made by PEG-R on this same topic.

In the 2007 report, PEG-R conducted research on the validity of including business variables into TFP projections. In that report, PEG-R states on page 49 that:

> The econometric models also provide us with an estimate of the effect of cast iron

authors of this article are the current president of PEG-R, Mark Lowry, and the co-author of this PSE Review, Lullit Getachew.

[11] The "electric customers" variable is obviously not relevant here.

> replacement on TFP growth. This could potentially be added to the econometric TFP trend target for Enbridge since it has been reducing the amount of cast iron on its system in recent years and expects to accelerate the replacement during the IR plan term. As discussed in Section 3.3.2, we found that cast iron mains raise total cost. This finding implies that a reduction in cast iron accelerates TFP growth in the long run. **However, the short and medium term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the installation of new pipe.** As an extra check, we therefore regressed the growth in the TFP of our sampled U.S. utilities on the change in their cast iron reliance using data for the sample period. **Using each approach to TFP capital costing, the estimated effect of reduced cast iron reliance was found to be statistically insignificant**. (Bold emphasis added.)

PSE conducted analysis similar to the PEG-R 2007 analysis, and we found similar results. The PSE analysis can be found in Section 3.3. In the analysis in Section 3.3, the percentage change in cast iron and bare steel is not a statistically significant driver of TFP trends. In fact, while our calculated result was not statistically significant, the coefficient estimate was negative, not positive. A negative coefficient here would mean that as utilities incur the costs of replacing cast iron and bare steel mains, their short-run TFP trends tend to *decline*.

This analysis, combined with PEG-R's 2007 analysis and their previously stated position provides a strong rationale for not including business condition variables in the TFP projections. If these variables are included, as in the 2011 PEG-R Report, it will lead to an upward bias in the expected TFP trends of EGD and the entire U.S. sample. This upward bias is demonstrated in Section 3.4.

Table 3-2 displays TFP projections without business condition variables (using the PEG-R 2007 methodology).

**Table 3-2 TFP Projections Using 2007 Method**

**TFP Growth Projections from Econometric Research for EGD**

| Sample Years | 2005-2007 | 2008-2010 |
|---|---|---|
| ***Elasticity Estimates from PEG-R cost model*** | | |
| Customers [A] | 0.716 | 0.716 |
| Line Miles [B] | 0.167 | 0.167 |
| Sum of Output Elasticities [C = A + B] | 0.883 | 0.883 |
| ***Output Index Weights from PEG-R cost model*** | | |
| Customers [D = A/C] | 0.811 | 0.811 |
| Line Miles [E = B/C] | 0.189 | 0.189 |
| ***Subindex Growth based on PEG-R Report*** | | |
| Customer [F] | 2.84% | 1.83% |
| Line Miles [G] | 0.52% | 0.49% |
| ***Output Growth (elasticity weighted)*** | | |
| [H = D*F + E*G] | 2.40% | 1.58% |
| **Returns to Scale [I = (1-C)*H** | 0.28% | 0.18% |
| **Technology Change [J]** | 0.63% | 0.63% |
| **TFP Projection "2007 Method" [K = J+I]** | **0.91%** | **0.81%** |

As is evident from Table 3-2, the TFP projections using the 2007 method are lower than PEG-R's 2011 "backcast" calculations for EGD over both examined time periods. (Recall that the PEG-R Report gave a backcasted value of 1.25% per year over 2008-2010.) EGD's measured TFP growth during the incentive regulation time period is (using the 2007 method predictions) more rapid than the TFP projection.

As PEG-R stated in the 2007 report, there is currently no statistical evidence to include the conversion from cast iron pipes into TFP growth. While the econometric model identifies this as a *long run* cost driver, this certainly does not necessitate that there will be a *short run* TFP influence. In fact, the evidence presented by PEG-R in 2007 and our update of that evidence appears to strongly contradict the inclusion of business condition variables.

Table 3-3 updates Table 3-1 using the results based on PEG-R's previous methodology. With this simple correction we note that EGD's TFP growth has outpaced the predicted level by 0.38% and 0.12% in the 3 years preceding IR and the 3 years during IR, respectively.

**Table 3-3 EGD's Measured and Expected TFP using 2007 Method**

| Time Period | Expected TFP Growth | Measured TFP Growth | Difference | Conclusion Based on Results in Table |
|---|---|---|---|---|
| 2005-2007 | 0.91% | 1.29% | 0.38% | EGD outperformed industry |
| 2008-2010 | 0.81% | 0.93% | 0.12% | EGD outperformed industry |

## 3.2 Enhancement #2: Use a Dataset with a More Applicable Time Period

PSE believes that Table 3-3 still does not accurately depict the TFP performance of EGD during the examined time period. This is because PEG-R developed the TFP projections using a dataset that included U.S. industry observations from 1999-2009 in order to develop predictions for the examined 2008-2010 incentive regulation time period. This mismatch in time periods significantly influences the predicted TFP value, primarily due to a higher time trend estimate.[12,13] Section 3.4 provides strong evidence on the impact and resultant bias of this mismatch.

In comparing the time trend estimate in the November 2007 report to the current one in the PEG-R Report, we notice a significant downward trend. In 2007, PEG-R used a dataset consisting of data from 1994-2004. By rolling the time period forward five years to 1999-2009, we see the time trend was almost halved. In the 2007 PEG-R report the 1994-2004 time trend was 1.19%, but now it is 0.63% (as calculated in the 2011 PEG-R Report, using the 1999-2009 time period).[14]

[12] A "time trend estimate" is a variable that: (1) reflects the trend of an average utility's total costs after adjustments for all other included variables (e.g. input price inflation) and (2) captures the trend in cost from other possible covariates that are not in the model.

[13] Given what appears to be PEG's definition of 2008-2010, whereby they are actually averaging the growth rates of 2007 to 2008, 2008 to 2009, and then 2009 to 2010, the dataset should include data from 2007 to 2010 in order to provide an "apples to apples" comparison to the estimated 2008-2010 TFP trend of EGD.

[14] This was using the "cost of service capital" costing method for both reports. In 2007, PEG-R reported econometric models for two methods of capital costing: cost of service and geometric decay. In the current report they only show results based on the cost of service method.

We see a significant slowdown in the technological change of the industry in recent years. This is also revealed in measured TFP trends that are declining in recent years. It seems very likely that if PEG-R had used a shorter and more comparable time period in its dataset, the time trend would have been further reduced.

PSE recognizes the requirement for a dataset containing a large enough number of observations to accurately estimate coefficient estimates. For example, a dataset containing only 2007-2009 data would only have 102 observations (3 years multiplied by 34 utilities) given PEG-R's sample of 34 utilities. Given the complexity and number of variables contained in their estimated translog cost function, there are likely not enough statistical degrees of freedom to limit the dataset to this short of a timeframe. However, given the industry TFP slowdown in recent years, the dataset should be limited to the most recent time frame available while still maintaining the integrity of the econometric model.

We attempted to shorten the dataset time span so that it more accurately reflects the time period that EGD is being compared against. This will provide a more applicable time trend estimate versus the dataset used by PEG-R. The PSE estimated time trend will be more reflective of the conditions faced by gas distributors during the 2005-2010 evaluation period. PEG-R's dataset includes the unnecessary influence of observations that occur in the late 1990's and early 2000's. Keep in mind, this is a preliminary analysis based on our "best guess" of PEG-R's data and econometric methods used.

The first econometric model that we estimated used the exact same specification as PEG-R (as far as we can tell) but limited the sample to 2002-2009. As expected, the time trend variable decreased to 0.13% in contrast to the PEG-R estimate of -0.63%. This finding was not statistically significant,[15] thus the null hypothesis of a trend value of 0.00% cannot be rejected. In this model, we also find that the transmission and distribution miles variable is no longer statistically significant; neither is the business condition variable of the number of electric customers served.

[15] The trend coefficient estimate of 0.0013 had an associated T-Statistic of 0.487, well below the T-Statistic threshold magnitude of 1.645 typically used to determine significance.

The table below shows the model estimates of the PEG-R model specification restricted to the more applicable time period of 2002-2009.

**Table 3-4 Model Estimates of the PEG-R Model**

| Model Variable | Coefficient Estimate | T-Statistic |
|---|---|---|
| Constant | 12.589 | 409.941 |
| Capital Input Price (K) | 0.502 | 103.368 |
| Total Customers (N) | 0.847 | 18.872 |
| Tx and Dx Miles (M) | 0.008 | 0.162 |
| % Dx Mains not Cast Iron or Bare Steel | -0.478 | -6.070 |
| Number of Electric Customers Served | -.001 | -0.675 |
| K*K | 0.030 | 0.911 |
| N*N | -0.166 | -1.694 |
| M*M | -0.229 | -2.266 |
| K*N | -0.037 | -3.770 |
| K*M | 0.037 | 3.962 |
| N*M | 0.192 | 2.483 |
| **Trend** | **0.0013** | **0.487** |

Since the line mile variable is statistically insignificant in the above model, PSE investigated modifying the PEG-R specification to substitute a variable based on volume delivered rather than line miles. Volumes are one of the primary billing determinants in gas distribution and most TFP and cost function models include volumes in their specification.

The econometric cost model defining residential and commercial volumes as an output is provided in the following table. Again, this uses the more applicable time period of 2002-2009 and keeps all other PEG-R variables the same, except for the substitution of residential and commercial volumes for transmission and distribution line miles. The volume variable (0.0607) is statistically significant at a 90% confidence level. The reader will notice the time trend, once again, is quite different from the trend used in the PEG-R Report. It is similar to the model discussed previously. It equals 0.10% and is a statistically insignificant.

**Table 3-5 Model Estimates of the PEG-R Model (with volume variable)**

| Model Variable | Coefficient Estimate | T-Statistic |
|---|---|---|
| Constant | 12.579 | 480.643 |
| Capital Input Price (K) | 0.506 | 90.885 |
| Total Customers (N) | 0.785 | 29.660 |
| Residential and Commercial Volumes (V) | 0.0607 | 1.805 |
| % Dx Mains not Cast Iron or Bare Steel | -0.333 | -6.463 |
| Number of Electric Customers Served | -0.003 | -1.683 |
| K*K | -0.055 | -1.277 |
| N*N | -0.094 | -0.686 |
| V*V | -0.288 | -1.680 |
| K*N | -0.028 | -1.839 |
| K*V | 0.038 | 2.368 |
| N*V | 0.175 | 1.156 |
| **Trend** | **0.0010** | **0.460** |

Given these two models, the consistency in the trend estimate, and the likelihood that the technology trend of the industry is approaching zero in recent years, PSE finds that a more applicable and conservative estimate for the technology trend is 0.00% rather than PEG-R's estimate of 0.63% (see Table 3-2 at [J]). This revised trend estimate lowers the expected TFP and further enhances the TFP performance of EGD relative to this expected TFP estimate. It provides a more accurate comparison to EGD's measured TFP growth during the incentive regulation period. The revised backcast table based on PSE's estimate of the trend variable is provided in the following table.

**Table 3-6 EGD's TFP Projections using Updated 2007 Method and More Applicable Time Period for Dataset**

**TFP Growth Projections from Econometric Research for EGD**

| **Sample Years** | 2005-2007 | 2008-2010 |
|---|---|---|
| ***Elasticity Estimates from PEG-R cost model*** | | |
| Customers [A] | 0.716 | 0.716 |
| Line Miles [B] | 0.167 | 0.167 |
| Sum of Output Elasticities [C = A + B] | 0.883 | 0.883 |
| ***Output Index Weights from PEG-R cost model*** | | |
| Customers [D = A/C] | 0.811 | 0.811 |
| Line Miles [E = B/C] | 0.189 | 0.189 |
| ***Subindex Growth based on PEG-R Report*** | | |
| Customer [F] | 2.84% | 1.83% |
| Line Miles [G] | 0.52% | 0.49% |
| ***Output Growth (elasticity weighted)*** | | |
| [H = D*F + E*G] | 2.40% | 1.58% |
| **Returns to Scale [I = (1-C)*H** | 0.28% | 0.18% |
| **Technology Change [J]** | 0.00% | 0.00% |
| **TFP Projection "2007 Method" and new trend [K = J+I]** | **0.28%** | **0.18%** |

The table below summarizes the predicted TFP with no business condition variables and the newly estimated trend variable. EGD outperforms its predicted annual TFP trend by 0.75% in 2008-2010 and by 1.01% in 2005-2007.

**Table 3-7 EGD's Measured and Expected TFP using Updated 2007 Method and Similar Time Period**

| Time Period | Expected TFP Growth | Measured TFP Growth | Difference | Conclusion Based on Results in Table |
|---|---|---|---|---|
| 2005-2007 | 0.28% | 1.29% | 1.01% | **EGD outperformed the industry by a large margin** |
| 2008-2010 | 0.18% | 0.93% | 0.75% | **EGD outperformed the industry by a large margin** |

## 3.3 Enhancement #3: Incorporate the Beginning Level Cost Efficiency of Enbridge

The third way in which the PEG-R TFP backcast method can be improved is to incorporate the cost efficiency level of the company when examining expected TFP trends. Gas distributors that are more efficient will have less room to trim costs and increase their TFP trend. Conversely, firms that start with relatively more inefficiency have more ability to cut costs, and thus have a more rapid TFP trend.

The previously referenced *Review of Network Economics* journal article states that "[a] decline (increase) in inefficiency will accelerate (decelerate) TFP growth."[16] Similarly, in the November 2007 report the authors state:

> TFP will grow (decline) to the extent that X inefficiency diminishes (increases). The potential of a company for TFP growth from this source is greater the greater is its current level of operating inefficiency. Evidence on operating efficiency can be produced using statistical benchmarking.[17]

[16] Lowry, Mark N. and Lullit Getachew, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," *Review of Network Economics* Volume 8, Issue 4 – December 2009, page 331.

[17] See page 7 of the November 2007 report to the Ontario Energy Board, "Rate Adjustment Indexes for Ontario's Natural Gas Utilities."

Thus, a proper TFP projection or prediction over the examined incentive regulation time period would have examined the relative cost efficiency of EGD. The PEG-R Report emphasizes a number of times that the TFP backcasts are applicable to a distributor of average efficiency.[18] The available efficiency improvements relative to the sample are necessary to accurately predict TFP trends.

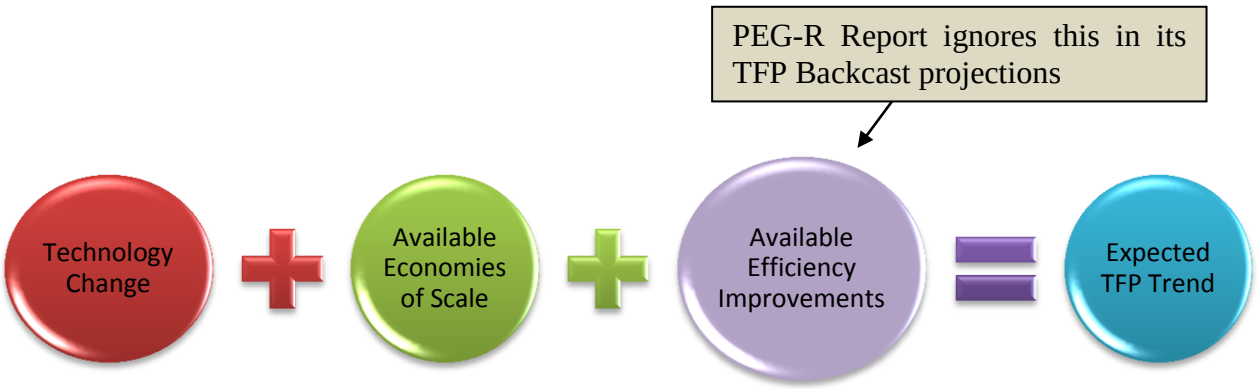



**Figure 3-1 TFP Components**

The Ontario Energy Board has recognized the relationship of cost efficiency and productivity trends. In its 3rd Generation Incentive Regulation plan for power distributors, stretch factors are tied to annual operation, maintenance, and administrative (OM&A) cost efficiency benchmarking scores. The benchmarking scores are based on industry quartile unit cost rankings and econometric benchmarking results. The stretch factors range from 0.2% for firms found to be top quartile and statistically significant cost performers, to 0.6% for firms found to be bottom quartile and statistically inferior performers. All other firms receive a stretch factor of 0.4%.

Operation and maintenance (O&M) spending can be most readily adjusted in the short-run. Whereas most capital expenses are fixed in the short-run, O&M spending levels are more flexible. It is logical that a firm that already has efficient O&M spending will have a lower potential to reduce this spending in the short-run. The starting O&M efficiency level needs to be considered when determining an expected TFP trend. Concentric finds EGD to be an efficient O&M cost performer compared to other North American gas distributors. Thus, EGD has much less room to boost its TFP trend by cutting its short-run O&M expenses.[19]

PSE has conducted research that quantifies the relationship between O&M cost efficiency and short-run TFP trends. Our findings indicate that TFP trends are significantly affected by the beginning year O&M cost efficiency. The relationship is such that firms found to have O&M per customer costs which are in the top quartile have short-run TFP trends which are lower than other firms.

[18] See, e.g., page 99 of the PEG-R Report.

[19] See Concentric's *Benchmarking Study*, most notably the O&M per customer findings of EGD relative to the industry.

For this research we limited our analysis to PEG-R's sample of 34 U.S. gas distributors. We then ranked this sample by the O&M cost per customer for each year beginning in 2002.[20] PSE identified the firms found to be in the top quartile (top eight firms) for each year through 2007. We then calculated 2-year TFP growth rates, 2-year customer growth rates, 2-year gas mile growth rates, and 2-year percentage of non-cast iron and bare steel growth rates for 2002-2009. This includes six observations per distributor: 2002-2004, 2003-2005, 2004-2006, 2005-2007, 2006-2008, and 2007-2009.

These variables allowed us to develop an econometric model that estimated the impacts of these variables and the top quartile designation on 2-year TFP trends. Our findings support many of PEG-R's assertions, such as the claim that growth rate in customers and gas miles will be positively correlated with TFP growth.

We also found that having a top quartile O&M per customer designation in the beginning year will tend to reduce TFP growth by 1.98%. Another finding was that the change in the percentage of non-cast iron and bare steel does not statistically influence TFP trends. In fact, the coefficient estimate is negative, which is the opposite of what PEG-R assumes when it includes business condition variables in its TFP backcasts (see Section 3.1). Additionally, the constant term supports PSE's finding in Section 3.2 that there is not a statistically significant technology trend when recent years are analyzed in determining expected TFP trends.

The table below provides the regression results and the finding that the O&M efficiency level has a strong and statistically significant influence on TFP trends. Furthermore, the change in the percentage of non-cast iron and bare steel mains is not a statistically significant driver of TFP trends, and in fact has a negative coefficient estimate, implying that growth in this term reduces (rather than increases) short-run TFP trends.

**Table 3-8 Regression Results for O&M Efficiency Level**

| Model Variable | Coefficient Estimate | T-Statistic |
|---|---|---|
| Constant | -0.001 | -0.287 |
| 2-Year Customer Growth | 0.557 | 3.587 |
| 2-Year Line Mile Growth | 0.465 | 2.788 |
| 2-Year % Non-Cast Iron and Bare Steel Growth | -0.104 | -0.637 |
| **Beginning Year Top Quartile** | **-0.0198** | **-4.407** |

Our results suggest that average annual TFP growth is reduced by approximately 1.98% relative to a normal firm if the firm is designated as a top quartile O&M cost performer on the basis of O&M per customer rankings. This finding is statistically significant at a 99% confidence level. Concentric's benchmarking results found in their January 2012 report *Benchmarking Study*, indicate that EGD is a strong O&M cost performer. Concentric finds EGD's 2009 O&M expenses per customer to be third in their sample, which consists of 35 U.S. and Canadian gas utilities. This is certainly a top quartile industry ranking. To account for this higher level of

[20] 2002 is the first year where SNL Energy makes available O&M breakdowns to enable us to mimic the O&M definition used by PEG-R in the PEG-R Report.

O&M cost efficiency, we find that 1.98% should be subtracted from the expected TFP trends of EGD.

Table 3-9 displays the expected 2008-2010 TFP trend for EGD using the finding that top quartile O&M cost performance lowers short-run annual TFP trends by 1.98%. The table provides very strong evidence of EGD outperforming the industry expected TFP trends during both 2005-2007 and 2008-2010. In fact, the difference appears to be well in excess of 200 basis points.

**Table 3-9 EGD's TFP using 2007 Method and Appropriate Comparison Period, Assuming Superior Cost Performer**

| Time Period | Expected TFP Growth (with all PSE Enhancements) | Measured TFP Growth | Difference | Conclusion Based on Results in Table |
|---|---|---|---|---|
| 2005-2007 | -1.70% | 1.29% | 2.99% | **EGD outperformed industry by a large margin** |
| 2008-2010 | -1.80% | 0.93% | 2.73% | **EGD outperformed industry by a large margin** |

We note that EGD appears to have significantly outperformed the expected annual TFP trends computed using PEG-R's TFP backcast methodology if PSE's three enhancements are made. The first enhancement was to simply revert to the method PEG-R used in their 2007 report. The difference relative to the current methodology is that business condition variable changes are not incorporated into the TFP projections. As stated earlier, it is not logical to incorporate a variable that is expected to have a long term impact, and not a short term impact, in a short term projection of TFP. PEG-R came to this same conclusion in its 2007 report, and PSE updated and verified their research in this report.

The second enhancement was to estimate the econometric trend parameter using a more applicable time period. For various reasons, the technology trend variable, and thus the industry TFP rate, has declined over recent years. As the econometric dataset is limited to more closely reflect the time period being investigated, we will have a more applicable time trend estimate to insert into the TFP projection. We do note, however, the requirement to have enough observations in order to estimate a robust econometric model. This is why PSE examined a 2002-2009 dataset, which we were able to use to estimate a valid model with statistically significant first order variables (except the time trend, which we would expect to be close to zero).

The third enhancement was to account for the O&M cost efficiency level of EGD. Concentric found EGD to be a cost efficient firm with top quartile O&M per customer spending levels. This higher level of efficiency represents a challenge to EGD for TFP growth, because the company cannot easily lower its already efficient O&M expenses. This is an excellent "problem" to have.

By being more efficient EGD is saving its customers money. However, this challenge is one that analysts should be aware of and adjust for when computing expected TFP trends and evaluating the historical TFP performance of EGD relative to the industry.

## 3.4 Bias Estimate of PEG-R Methodology

The virtue of the three improvements suggested above can be seen by comparing the apparent bias in the original PEG-R methodology relative to the methodology as improved by PSE. This serves as an independent confirmation of the validity of PSE's suggested improvements to PEG-R's backcast (over and above the rationale already provided for the improvements in Sections 3.1 to 3.3 of this PSE Review). In this section we test the performance of our models by seeing how well they predict the actual outcomes they are attempting to model.

In performing this confirmation, PSE began by estimating the average 2007-2009 TFP trends of the 34 gas distributors cited in PEG-R's Report.[21] Without access to the actual data and methods used by PEG-R to calculate their TFP trends, we reiterate that this is a preliminary assessment. We attempted to replicate the data and methods used by PEG-R. We also used the sample of 34 U.S. gas distributors to provide consistency with PEG-R's analysis; however, this should not imply that PSE feels this is the best available group of utilities to compute EGD expected TFP trends.

PSE's estimate of the average annual TFP trends of the sampled 34 gas distributors *declined* by 0.77% from 2007 to 2009. The output quantity index, which used the same output weights as suggested by PEG-R, grew at an average annual rate of 0.50%.[22] The input quantity index grew at an average annual pace of 1.27%. Notice that a TFP trend is simply the change in an output index minus the change in an input index, so 0.50% - 1.27% = -0.77%.

The PEG-R TFP backcast methodology was implemented on the entire U.S. sample to determine what the average TFP backcast estimate would be for the sample. This is the same method used by PEG-R to evaluate the IR period TFP growth of EGD in the PEG-R Report. Recall that PEG-R included business condition variables, used a 1999-2009 sample timeframe, and did not account for the relative efficiency of each firm.

Using the PEG-R method, PSE estimates the average TFP backcast of the U.S. industry would increase annually by 0.94%. This is compared to the estimated TFP *decline* of 0.77% during that same period. This amounts to an observed upward bias of 1.71% in the PEG-R Report. Table 3-10 below summarizes these findings.

[21] We examine 2007-2009 because this is the most recent data available for EIA-176 data providing information on the number of customers and volumes for U.S. gas distributors during the time of the analysis by PSE. The 2009 end year also matches PEG-R's U.S. dataset allowing for consistency. 2010 EIA-176 data is now available.

[22] We used PEG-R's output definitions of customers and line miles and the weights used for these outputs. We did this for consistency despite our finding in Section 3.2 that volumes is probably a better output variable to use relative to line miles. Including volumes would certainly be more in line with historic measurements of TFP within the energy utility industry.

**Table 3-10 Comparison of Measured and Average Industry TFP Backcasts (using PEG-R Method)**

| Time Period | Average Measured TFP Growth | Average TFP Backcast using 2011 PEG-R Methodology | Observed Bias |
|---|---|---|---|
| 2007-2009 | -0.77% | 0.94% | **1.71%** |

As observed in Table 3-10, there appears to be a large amount of bias in the PEG-R TFP backcast methodology as presented in the PEG-R Report. PSE's preliminary assessment of this bias is that PEG-R's method overstates expected 2007-2009 TFP growth by 1.71%. If the method were truly unbiased, we would expect the average TFP backcast to approximate the average measured TFP growth. Instead, the PEG-R method produces, on average, TFP growth that is significantly higher than the average observed value.

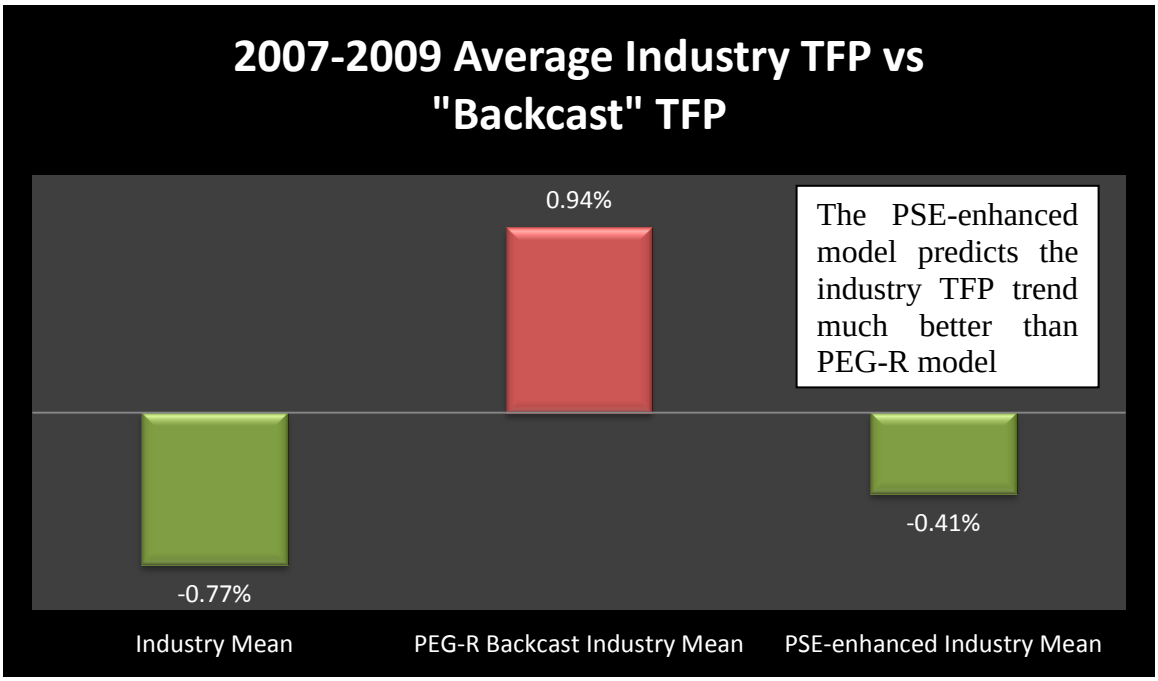
As an added check to PSE's suggested enhancements to the PEG-R method, found in Sections 3.1, 3.2, and 3.3, we tested the PSE-enhanced version of the TFP backcast to see if it provided less observed bias. Our analysis is that our method reduces the bias from 1.71% to 0.36%. This provides strong evidence that the methodological enhancements suggested by PSE are improvements and provide more reliable expected TFP values. It is also noteworthy that PSE's model still shows a slight upward bias, thus PSE's conclusions regarding expected TFP trends based on this model are likely to be conservative.

Table 3-11 below summarizes the PSE-enhanced TFP backcasts relative to the average TFP growth observed from 2007 to 2009.

**Table 3-11 Comparison of Measured and Average Industry TFP Backcasts using PSE-Enhanced Methodology**

| Time Period | Average Measured TFP Growth | Average TFP Backcast using PSE Improvements | Observed Bias |
|---|---|---|---|
| 2007-2009 | -0.77% | -0.41% | **0.36%** |

As observed in Table 3-10 and Table 3-11, the PSE-enhanced TFP backcasts are much more accurate and contain significantly less bias than the PEG-R method employed in the PEG-R Report. The PSE-enhanced version is only "off" by 0.36% relative to the measured average TFP trend, while the PEG-R method is off by 1.71%.




This evidence should put into doubt the current PEG-R method of determining expected TFP growth through the use of a long-run econometric model. It certainly appears that the PSE enhancements significantly improve the performance of the model and, thus provide much more accurate expected TFP trend estimates. Our analysis also raises important questions about using customized TFP expectations at all, rather than the more customary method of using an industry-wide peer group (or at least a large group) to fashion TFP expectations.

# 4 Comments on PEG-R's TFP Peer Group

In Chapter Six of the PEG-R Report, the backcast model results are supported through a comparison of EGD and Union to selected U.S. peer groups. PEG-R writes on page 109:

> Overall, we believe these comparisons with specific distributors identified as "peers" reinforce the conclusions of PEG-R's backcast model, which shows that EGD has greater opportunity to boost its TFP growth, and achieve incremental TFP gains, than does Union.

Later in this chapter we will discuss how a peer group consisting of only two or three utilities is inadequate and makes the analysis extremely vulnerable to outlier observations and low quality data. However, even if we take the comparisons presented by PEG-R at face value, the results actually appear to support PSE's findings in Chapter 3 that EGD outperformed its expected TFP trend during the examined incentive regulation period.

PEG-R used two separate peer group comparisons. PEG-R first began by comparing EGD's and Union's TFP trends with U.S. gas distributors operating under incentive regulation plans. The U.S. IR distributors used were Atlanta Gas Light, Bay State Gas, and Boston Gas. The calculated TFP trends from 2004-2009 varied considerably for the three utilities with an average TFP trend of 0.02%.

PEG-R also constructed a peer comparison with two other U.S. gas distributors. This second peer analysis compared EGD and Union with two other gas distributors, New Jersey Natural Gas and Washington Gas Light. Again the TFP results differed considerably for these two peer utilities, with an average TFP trend of 0.44%.[23]

The results of the two peer group comparisons appear to be very much in line with PSE's findings in Chapter 3 that EGD outperformed its expected TFP trend. EGD outperformed the U.S. IR utilities' TFP by 1.05% and the identified peer utilities by 0.63%. Note that PEG-R used a 2004-2009 time frame for the U.S. companies and a 2005-2010 time period for EGD.

**Table 4-1 EGD's Measured and PEG-R Comparison TFP Trends**

| EGD TFP Growth | U.S. IR TFP Growth | EGD Difference from U.S. IR | U.S. Peer Comparisons | EGD Difference from Peer |
|---|---|---|---|---|
| 1.07% | 0.02% | **1.05%** | 0.44% | **0.63%** |

Despite this substantiation of PSE's findings that EGD outperformed its expected TFP trend, we believe developing peer groups consisting of only two or three utilities is insufficient and leaves

[23] These two utilities (New Jersey Natural Gas and Washington Gas Light) were selected on the basis of cluster analysis. It was assumed that Union Gas and EGD were peers in the analysis. This assumption and other assumptions should be further examined during the discovery process to determine their impact on the findings.

the research vulnerable to outlier observations and the possibility of poor quality data from a few utilities driving the analysis. PEG-R previously held this same view. In a separate report submitted to the Ontario Energy Board regarding the cost benchmarking of the power distribution industry, PEG-R wrote:

> As a practical manner, this means that it is desirable for benchmarks to be based on several years of data for several companies. In our experience, it is generally desirable for peer groups to have more than five members.[24]

Given that TFP trends are essentially measuring the relative cost efficiency of a firm in the last year to that same firm in the first year, unless a firm is substantially different than the industry there is no reason to depart from the conventional method of determining expected TFP trends. This conventional method relies on an industry-wide TFP trend, or on a substantially large peer group's TFP trend. This protects the researcher from making conclusions based on outlier observations and poor quality data.

PEG-R identified three variables that they found to be most relevant in determining expected TFP growth for EGD. These are the change in the number of customers, the change in kilometers of line, and the trend in the percentage of main that is not cast iron or bare steel.[25] The following figures present the changes in these three variables over the examined time period. These figures are based on data gathered by PSE from SNL Energy and thus are preliminary, based on our best guess of the variable definitions and data used by PEG-R. Once the discovery process is complete, we will be able to use the actual data used in the PEG-R analysis.[26]

PSE believes that these figures provide no strong evidence for departing from the conventional method of benchmarking TFP growth to industry or a large peer group average. To see why, consider the three figures shown below. The first figure displays EGD's relative ranking in customer growth rate over 2005-2009 to the U.S. sample of 34 gas distributors used in the PEG-R Report.[27] EGD is one of the faster growing utilities in the sample, in terms of customer additions. However, three other utilities are at or above the level of EGD and there are a number of gas distributors with similar growth rates.

[24] "Benchmarking the Costs of Ontario Power Distributors," March 20, 2008, p. 18, found at:

http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0268/PEG_Final_Benchmarking_Report_20080320.pdf

[25] See page 143 of the PEG-R Report. The peer group selection was based on the changes in four variables (customer numbers, miles of main, number of electric customers, and percent of distribution main not constructed of cast iron or bare steel). Since EGD does not serve electric customers and this has not changed, only three of the variables are relevant to the company according to PEG-R.

[26] PSE is not endorsing the PEG-R data or sample as the best available.

[27] We compare the 2005-2009 growth rates of the companies to EGD's 2005-2010 growth rates calculated in the PEG-R Report.

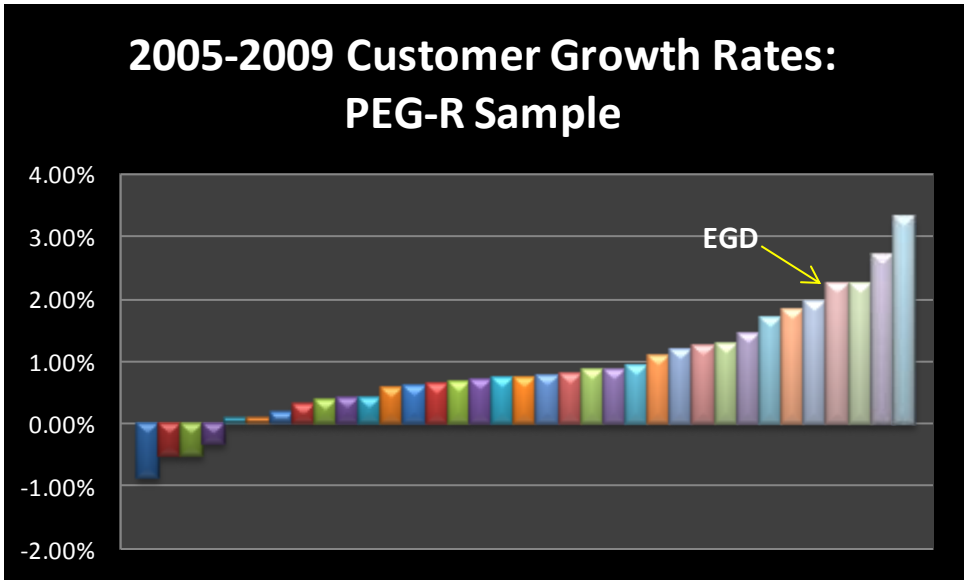



**Figure 4-1 EGD's Relative Ranking in Customer Growth Rate from 2005-2009**

Figure 4-2 displays EGD's annual growth rate in the length of mains relative to the U.S. sample. Contrary to the growth in customers, EGD's line growth has been on the lower end of the sample spectrum. This serves to balance out the TFP advantages found in the customer growth figure.

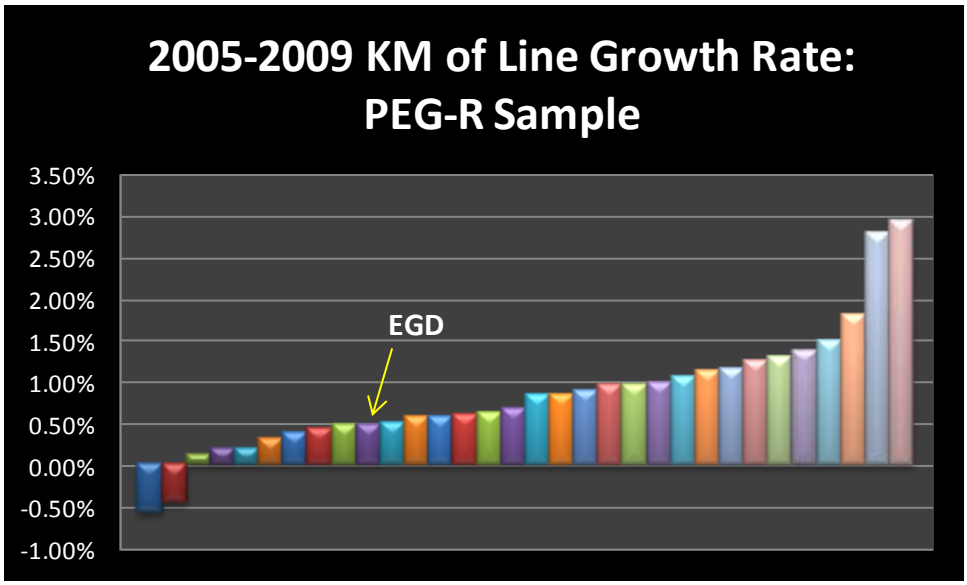



**Figure 4-2 EGD's Annual Growth Rate in the Length of Mains**

The next figure displays the annual change in the percentage of non-cast iron or bare steel in total distribution mains. The PEG-R Report claims that higher TFP growth rates should result from higher replacement rates of cast iron and bare steel. While PSE does not see solid evidence for this claim in determining short-run TFP trends, if the PEG-R claim were true then EGD

would be disadvantaged in its TFP trend, as its percentage of non-cast iron or bare steel is growing slower than most in the U.S. sample.[28]

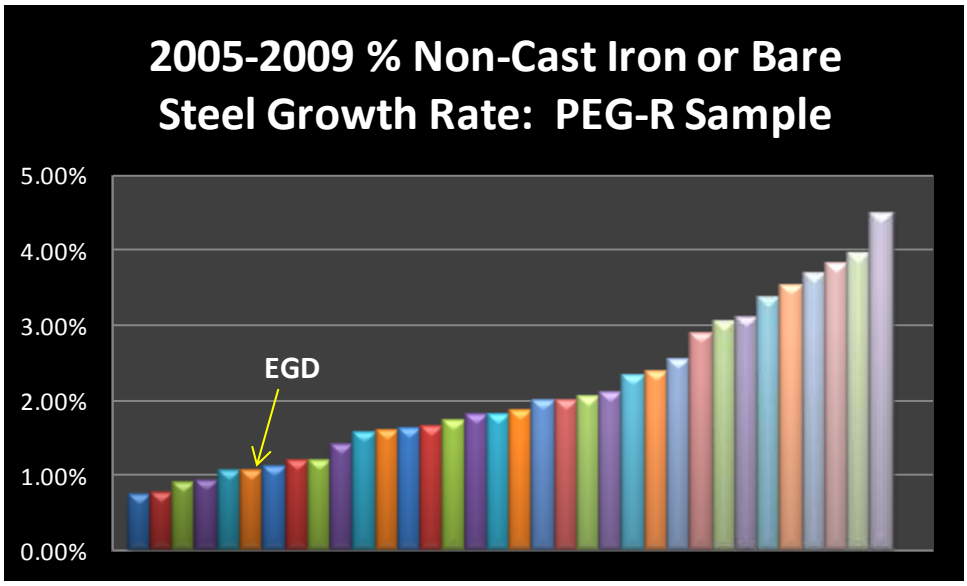
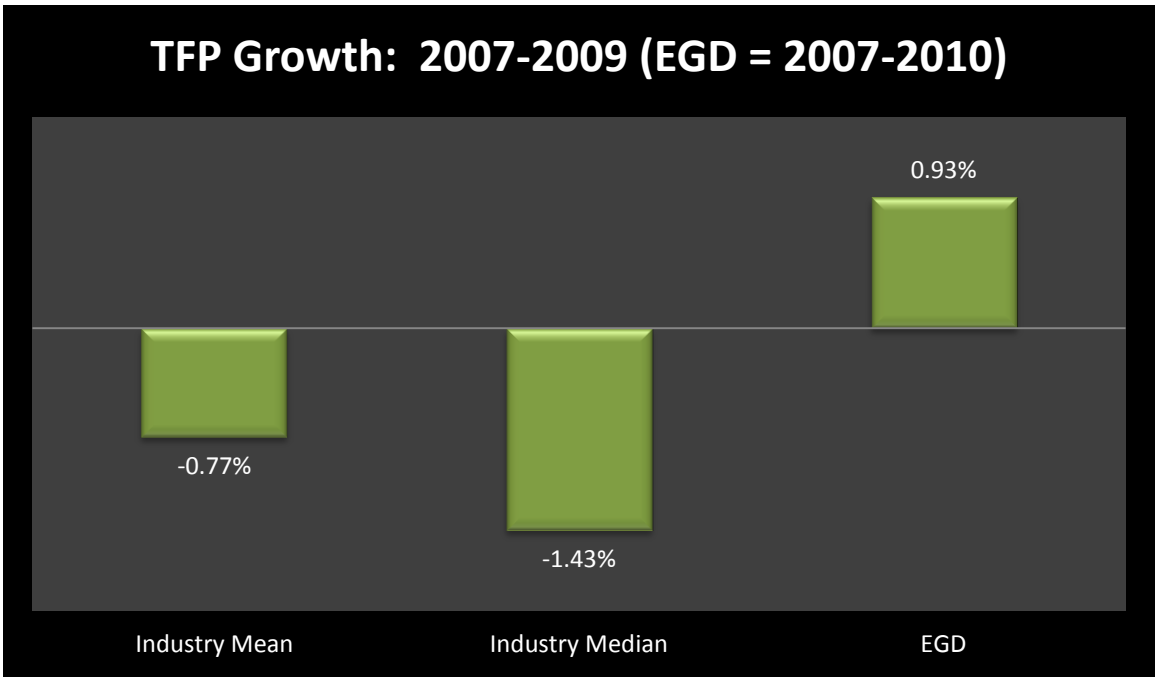



**Figure 4-3 Annual Change in the Percentage of Non-cast Iron or Bare Steel in Total Distribution Mains**

As displayed in the three figures above, EGD is certainly not an outlier in the three relevant variables identified by PEG-R as driving TFP growth. In fact, in two out of three of these variables EGD is actually disadvantaged. The rationale for departing from a larger peer group or the U.S. industry based TFP comparison is not evident from our preliminary analysis. A large peer group or industry analysis would provide more stable and unbiased results.

PSE attempted to replicate the TFP trends for the PEG-R sample based on their TFP calculation methods (again, we do not judge these methods at this time). Without access to the actual data values and exact methods used by PEG-R, this replication is only approximate. Our preliminary findings are that in recent years, the industry average and median TFP trend has been negative. We compare this negative U.S. industry trend to EGD's measured performance of 0.93% in the graph below.

[28] It does appear true, however, that in the long run total costs will be reduced by transitioning mains from cast iron and bare steel. This likely provides evidence for increased capital spending to accelerate this transition. While short run costs and capital spending will likely increase, according to PEG-R's econometric findings this will probably pay dividends in the long run.




This strong performance has resulted in lower gas delivery rates for customers and lower total costs for EGD. We should caution, however, that outperforming the industry by almost 200 basis points per year cannot continue indefinitely. It is likely that these strong TFP performances, combined with EGD's current low level of O&M spending per customer (see Concentric's *Benchmarking Study*) will necessitate future TFP trends to more closely mimic standard industry trends. However, EGD's customers will continue to benefit from these higher than normal 2005-2010 TFP trends well into the future, as these productivity gains are now embedded into the cost structure of EGD.

# 5 Implications for the "Backcast" X-Factor

It is useful to investigate EGD's X-factor for 2008-2010 in light of the PSE-enhanced expected TFP and input price experience. This assessment of the incentive regulation plan is important to determine if EGD benefitted from an X-factor that was too low, or if its gas customers benefited from an X-factor that was too high. We conduct this "backcast" X-factor analysis using PEG-R's methodology supplemented by the enhancements found in this report.

This analysis is meant to only examine what the historical X-factor should have been, now that the historical information is available. Naturally, at the time the X-factor was calibrated this information was not available. This research is not meant to prescribe a future X-factor but merely inform what a proper X-factor would have been for 2008-2010, given the now-available information.

EGD is currently regulated based on a revenue-per-customer cap mechanism. This is a type of incentive regulation plan due to the external nature of the allowed annual revenue escalations. Annual allowed revenue requirements are calculated mainly through a pre-set formula which incorporates economy-wide inflationary measurements and customer counts.[29] These items are external to the firm and not under its control. The current adjustment formula for the distribution revenue requirement in each year of the incentive regulation plan is:

$$DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * I) * C_t + Y_t + Z_t$$

**Where:**

DRR = the distribution revenue requirement
t = the rate year
C = the average number of customers
P = the inflation coefficient
I = the inflation index
Y = pass-throughs at cost of service
Z = exogenous factors

Of particular importance in the above adjustment formula is the means by which the previous years' revenue requirement is escalated. Essentially the escalation is accomplished through multiplying the previous year's revenue requirement by the customer growth ratio ($C_t/C_{t-1}$) and an adjusted economy-wide inflation factor. Within this inflation factor is an implicit adjustment for items such as expected productivity, industry input price differentials, and a stretch factor. These items are referred to as the "X-factor." The X-factor in the above formula is equal to one minus the inflation coefficient multiplied by the inflation index.

$$X = 1 - P*I$$

[29] The inflation rate used in the current IR plan is based on the Canadian GDP IPI (FDD).

## 5.1 X-Factor Mathematical Foundations

The rationale for incentive regulation including an X-factor is founded on economic cost theory. We start with a commonly accepted equation in economics, that cost equals input prices times input quantities.

Cost (C) = Input Prices (W) * Input Quantities (Q) **[Equation 1]**

Equation 1 can be translated into the annual trend in cost by adding the trend in input prices and the trend in input quantities.

trend C = trend W + trend Q **[Equation 2]**

Assuming the goal of a revenue cap per customer incentive regulation plan is to have a utility's allowed revenues track its expected costs (or revenue requirement), we can substitute revenues (R) into the left-hand side of Equation 2.

trend R = trend W + trend Q **[Equation 3]**

The next step is to simply subtract the trend in customers (N) from both sides of Equation 3.

trend R – trend N = trend W + trend Q – trend N **[Equation 4]**

The left-hand side of Equation 4 will then equal the trend in the revenue per customer (RPC), and the right hand side can be rearranged as shown below.

trend RPC = trend W – (trend N –trend Q) **[Equation 5]**

Rather than the actual industry input price trend, the Canadian GDP-IPI (we'll refer to this as "I") is used in Enbridge's incentive regulation equation. If we add and subtract I from the right hand side of Equation 5 we get equation 6.

trend RPC = I + (trend W – I) – (trend N –trend Q) **[Equation 6]**

The last adjustment needed before defining the X-factor for an RPC incentive regulation plan is to adjust for the trend in the output index. PEG-R incorporates both customers and line miles as outputs based on their cost elasticity weights to determine the expected TFP trend. We do this by simply adding and subtracting the trend in the output index, which includes both customers and line miles (Y), from the right-hand side of Equation 6.

trend RPC = I + (trend W – I) – (trend Y – trend Q) – (trend N - trend Y)
**[Equation 7]**

Notice that the term (trend Y – trend Q) is the definition of the TFP trend. The term (trend W – I) is the input price differential (IP) between the industry input prices faced by EGD and the GDP-IPI trend used in the calculation. The last term is the difference between the customer trend and the output index trend (OD).

trend RPC = I – (TFP + OD – IP) **[Equation 8]**

The term in the parenthesis (TFP + OD – IP) is the appropriate X-factor for an RPC incentive regulation plan, such that:

trend RPC = I – X **[Equation 9]**

## 5.2 Backcast X-Factor and IR Plan X-Factor

We can now examine what an appropriate X-factor for EGD would have been, given the actual industry conditions and results from 2008-2010. In Section 3, the expected TFP of EGD during 2008-2010 was calculated to be -1.80%. On page 63 of the PEG-R report, the price differential between the industry input price trend and the GDP-IPI is stated to be 0.45%. Using Equation 8 above, IP thus equals 0.45%. The output differential between the cost elasticity weighted output index and the customer-only index for EGD during 2008-2010 equals 0.25% (1.83% - 1.58%).[30]

**Table 5-1 Revenue per Customer X-Factor Calculations**

| | |
|---|---|
| EGD Expected TFP for 2008-2010 [TFP] | -1.80% |
| Customer and Output Index Differential [OD] | 0.25% |
| GDP-IPI Differential [IP] | 0.45% |
| Backcast X-Factor [TFP +OD - IP] | -2.00% |

According to Table 2 of the PEG-R Report, EGD's average measured X-factor during 2008-2010 equaled 0.72%. The calculated Backcast X-factor of -2.00% provides evidence that EGD faced a very challenging X-Factor during 2008-2010, based on the actual experience of the U.S. gas industry. Its measured X-factor was 2.72% greater than what the Backcast X-factor would suggest to be appropriate. This reinforces the finding that EGD performed exceptionally well during the 2008-2010 time period and that its customers benefited from this performance.

**Table 5-2 EGD's Measured X-Factor**

| IR Measured X-Factor | Backcast X-Factor | Difference |
|---|---|---|
| 0.72% | -2.00% | **2.72%** |

[30] This information can be found and calculated on Table 21 of the PEG-R Report. EGD customer growth is equal to 1.83%. The output index growth is calculated by taking the output index weights of 81.05% and 18.95% for customers and line miles, respectively, and multiplying by the growth in each output 1.83% and 0.49%, respectively.

# 6 Findings and Conclusions

In this Review, PSE has conducted an examination of PEG-R's methodology used to calculate EGD's benchmark TFP trend. A more thorough investigation should be undertaken once the PEG-R Report is filed and the discovery process begins. Our preliminary assessment has uncovered that the methods used by PEG-R in fashioning the expected TFP trends of EGD can be substantially improved.

Using the improved methodology, our preliminary analysis finds that EGD *outperformed* its expected TFP trend during the examined IR period (See Table 3-9). EGD's annual measured TFP trend of 0.93% is over 200 basis points greater than the expected trend we estimated in Chapter Three of this report. This refutes PEG-R's conclusion that EGD has scope to increase its TFP trend beyond the measured 0.93%. In fact, the opposite is likely to be true.

Our preliminary research in this document provides strong evidence that EGD's productivity trend was well above most of its peers and provided strong value to stakeholders. This rapid productivity trend has provided consumers with lower rates than would have normally been the case.

## 6.1 Improvements to the PEG-R Method

PSE has uncovered **three primary causes** for why PEG-R's expected TFP trend is inflated.[31] The **first cause** is PEG-R's inclusion of business condition variables, in particular the percentage of cast iron and bare steel, in the TFP backcast calculation. By including the business condition variables into the analysis, PEG-R is assuming that long run cost savings resulting from less cast iron and bare steel pipes will all be realized in the short-run, in this case three years.

The conclusion that by spending more money on main replacement, a utility's short-run TFP is expected to increase appears faulty at face value. While based on PEG-R's estimated *long run* cost function, it does appear that lowering the percentage of cast iron and bare steel mains reduces costs, this in no way necessitates a *short term* cost savings that would boost expected TFP trends.

PEG-R personnel in past reports to the Ontario Energy Board have stated the rationale of not including business condition variables in such an analysis, and have even conducted regression analysis to support this claim. PSE has verified these previous findings. No evidence in the PEG-R Report was put forth to contradict these prior claims. Until convincing evidence is provided that the observed long run cost implications of converting cast iron and bare steel mains can be translated into short run cost savings, the inclusion of business condition variables into the TFP backcast methodology is not warranted.

The **second cause** for the inflation of PEG-R's expected TFP trend is that the estimates are based on a dataset starting in 1999 and ending in 2009. On the other hand, the dataset used to compute EGD's measured TFP trend covers the years 2005 to 2010.

[31] This statement does not mean there are not other issues with PEG-R's method.

The gas industry has seen a slowdown in productivity. Aged capital has necessitated replacement, and the recession has reduced output growth. Using a dataset that is not reflective of these conditions will inherently bias the analysis against a utility being evaluated during the more recent time period. PSE used a more applicable and recent dataset spanning from 2002-2009. Our findings are that the technology trend is no longer statistically significant (and even reverses signs) when a more applicable time period is used. Thus, we have set the technology trend estimate to zero in our analysis.

The **third cause** for an inflated PEG-R EGD expected TFP trend was not incorporating the strong O&M cost performance of the firm. Other sampled firms have a larger ability to reduce costs through improving the efficiency of their operations. Given EGD's current strong O&M cost efficiency, as cited in a report prepared by Concentric Energy Advisors, they have much less available potential to improve. PSE estimates that firms that start with top quartile O&M per customer cost efficiency are expected to have 1.98% lower annual TFP trends for the subsequent two years.

In Section 3.4 of this review, we tested the validity of the PSE enhancements relative to the method found in the PEG-R Report. We did this by comparing the measured U.S. sample average TFP trends to the average produced by each method. We found that the PEG-R method, as detailed in the PEG-R Report, appears to have an upward bias in the expected TFP level of 1.71%. When PSE's suggested enhancements are introduced, the bias is substantially reduced to 0.36%. This provides solid evidence for the reasonableness and increased accuracy of the enhancements suggested to calculating expected TFP trends.

## 6.2 Peer Group Analysis and X-Factor Analysis

PSE also believes the peer group analysis found in Chapter Six of the PEG-R Report, while supporting PSE's findings of slower expected TFP growth for EGD, includes far too few utilities to be reliable. There is little reason to depart from the more conventional method of determining expected TFP growth through an industry-wide or large peer group TFP study. PEG-R identified three relevant TFP trend determinants in its analysis. These are the changes in the number of customers, line length, and the percentage of non-cast iron and bare steel. As shown in Chapter Four, EGD is certainly not unusual in any of these TFP determinants. In fact, for two out of the three determinants, EGD actually faces more challenging conditions during 2008-2010 than the U.S. industry sample used by PEG-R (although we dispute the relevance of the percentage of non-cast iron and bare steel).

The expected TFP growth calculated by PSE during the 2008-2010 period is combined with the PEG-R findings of challenging input prices relative to the Canadian GDP-IPI to determine a Backcasted X-Factor. PSE's findings that the implicit X-Factor of 0.72% faced by EGD during 2008-2010 is 2.72% above the appropriate X-Factor given the company's TFP trend, output growth, and input price inflation. Given proper X-Factor mechanics and the benefit of hindsight, the X-Factor during 2008-2010 would have been set at -2.00%.

## 6.3 Summary

In summary, the PEG-R Report includes a number of accurate and positive findings in the assessment of incentive regulation and EGD's performance within that framework. However, our

analysis indicates that PEG-R's calculations of EGD's "expected" total factor productivity are inflated. This results in PEG-R's inaccurate conclusion that there is substantial room for EGD to boost its total factor productivity (TFP). We find that EGD has significantly outperformed the U.S. industry to the benefit of its customers. These cost savings are now reflected in EGD's cost structure and will help to keep gas delivery rates low. It is unlikely, however, that with EGD's historic high TFP trends and top quartile cost efficiency that this rapid productivity pace can be maintained indefinitely.

The implicit X-factor of 0.72% faced by EGD was far more challenging than what the historical data would have suggested. PSE estimates the appropriate Backcast X-Factor to be -2.00%. This provided very strong value to EGD's customers; even while the company faced increasing input price pressures, the gas delivery prices actually declined during the 2008-2010 time period. The bottom line is that PEG-R's claim that EGD has room to improve its TFP is incorrect: EGD has actually outperformed its expected TFP, and is likely to trend closer to that expected TFP in the future.

# About PSE's Economics and Market Research Group

Founded in 1974, PSE is a full-service consulting firm. PSE's benchmarking experience includes research for regulatory purposes and utility management improvement. Our benchmarking team consists of economists, planning and design engineers, rate and financial analysts, communications infrastructure consultants, and smart grid technology experts. In addition to our statistical cost research, PSE's Economics and Market Research group has expertise in the areas of demand response, energy efficiency, value-based reliability planning, T&D reliability benchmarking, merger valuations, load forecasting, load research, survey design, alternative regulation, and cost of service studies. For more information on PSE and a full list of services, visit our website at www.powersystem.org.

# About the Authors

### Steve Fenrick, Leader - Benchmarking and Economic Studies

Mr. Fenrick has over a decade of consulting experience in the evaluation of utility performance. He leads PSE's benchmarking and economic study practice areas. He has provided expert witness testimony on performance benchmarking and authored numerous reports on the topic. He is the conference chair for a semi-annual EUCI conference on measuring and improving the cost and reliability performance of energy utility distributors. Mr. Fenrick has evaluated performance relating to electric and gas distribution, power transmission, power plant performance, and water distribution. These evaluations have been conducted for utilities, regulatory agencies, and consumer advocates. Mr. Fenrick has a Master's degree in Applied Economics from the University of Wisconsin and a BS in economics from the same university.

### Lullit Getachew, Senior Economist

Dr. Getachew has experience in conducting research and analysis in support of benchmarking projects for energy utilities. She has written a number of academic journal articles on benchmarking and performance evaluation. She has also prepared studies and reports for performance-based regulation of transmission and distribution energy businesses, undertaken total and operation cost benchmarking, prepared reports for rate settlements, and marketed flexibility in rate designs. Dr. Getachew earned her doctorate in Economics at Rice University, her Master of Arts in Law and Diplomacy at the Fletcher School at Tufts University, and her BA *magna cum laude* from Mount Holyoke College.

**Enbridge Gas Distribution Inc.**
**Raymond Lei**
Manager, Budgets & Business Support
500 Consumers Road
North York, ON, M2J 1P8
Tel 416 495 3927
Fax 416 495 6451
Raymond.lei@enbridge.com

# Memo

Date: April 26, 2011

To: Distribution List

From: Raymond Lei

Re: **EGD 2012 and 2013 Budget Assumptions and Guidelines**

The purpose of this document is to set out guidelines to be used in preparation of EGD's ("the Company") **2012 Corporate Budget and 2013 Regulatory Budget**. A number of core developments in the 2011 budget cycle are highlighted as follow:

1. The 2012 Corporate Budget and the 2013 Regulatory Budget are to run in parallel in the same timeline of the 2011 budget cycle.

2. The Company is aiming to file its 2013 rate case on **November 7th, 2011.**

3. Khalix Ensight opens one month earlier than usual to accommodate the development of dual budgets. Khalix Ensight opens from **May 2nd, 2011** to **June 3rd, 2011** for O&M, capital, and FTE budget inputs.

4. The Company plans to adopt **USGAAP** as the accounting standard starting January 1st, 2012. Under USGAAP, the capitalization policy assumes status quo.

5. O&M budgets should be built on a **sustainable, acceptable, and defendable** basis to align with the expectations from the EMT.

6. Departments will need to prepare regulatory evidence for the 2013 rate case filing.

7. The new Workforce Planning ("WFP") process requested by Enbridge Inc. HR is integrated with the budget process and will be rolled out in this budget cycle.

8. New fields for vacancies in the FTE module have been set up to capture the vacancy budget separately. Please refer to Appendix C for details.

**PLEASE REFER TO THE FOLLOWING FOR SPECIFICS:**

**1. Rationale for Early 2013 Budget**

The 2012 Corporate Budget, which is the last year of the five-year Incentive Regulation ("IR") Agreement, follows the normal course and time frame of the budget cycle. The current five-year IR Agreement expires at the end of 2012 and under this Agreement, the Company is required to rebase in 2013 by filing a Cost of Service application with the Ontario Energy Board ("OEB").

In order to have new distribution rates in place on January 1st, 2013, the Company needs to develop the 2013 Regulatory Budget in the 2011 budget cycle given that completion of a typical Cost of Service proceeding may take more than a year . The 2013 rate case is scheduled to be filed with the OEB on November 7th, 2011.

**2. Accounting Standards for Dual Budgets**

The planned conversion of accounting standards from Canadian Generally Accepted Accounting Principles ("CGAAP") to US Generally Accepted Accounting Principles ("USGAAP") starting January 1st, 2012 assumes no impact on O&M and capital budget at this stage based on the assessment of current state. As a result, the capitalization policy remains **unchanged** for both 2012 and 2013 Budget, which means that departments can continue to use the existing salary allocation rules (server rules) to develop O&M and capital budgets.

**3. Budget Approach**

| Cost type | Budget Approach | Budget System |
|---|---|---|
| Labour cost | Pre-populated labour input template incorporates two elements:<br>1. Employee details and salary data from PeopleSoft as of **April 15th, 2011**<br>2. Salary increases are programmed for both 2012 and 2013 based on April 15th, 2011 HR load (Refer to Appendix C for salary increases) | Khalix Ensight |

| | | |
|---|---|---|
| Non-labour cost | A hybrid of zero-based and incremental:<br>• Operations – incremental<br>• All other departments – zero-based | • Enbridge Budget Input Tool (EnBIT)<br>• Khalix Ensight |

**4. Sustainable, Acceptable, and Defendable O&M**

EMT has set clear direction and expectations with respect to O&M budget for 2012 and 2013. Departments are required to come up with O&M budgets at a reasonable level in the context of year over year growth which are sustainable and acceptable to EMT. Sustainable O&M is the level of spending the Company can operate effectively regardless of the regulatory economic models: Cost of Service or Incentive Regulation. There is no top-down numerical target for departments to comply with given that departments are in a better position to assess and justify their own sustainable levels.

**5. Protocol for Changing the Budget**

Departments are responsible for both accuracy and completeness of the budget. There is no room to change the budget once the budget is approved by the EMT and is filed with the OEB. The onus is on departments to ensure their budgets are complete and free from errors. Any corrections and revisions beyond the cut-off date would be difficult to reflect.

**6. Budget Analysis**

To accommodate both the corporate budget review and the regulatory rate case filing, the budget analysis will be combined into one to minimize multiple efforts. The analysis template will be sent out separately. The chart lays out the framework of the template.

| 3-Year Financial Data | Year over Year Comparison | Cost Analysis |
|---|---|---|
| • 2011 5&7 Forecast – Proxy as Historical year<br>• 2012 Budget – Proxy as Bridge year<br>• 2013 Budget - Test year | • 2011 vs. 2012<br>• 2012 vs. 2013 | • Salary increases<br>- Management<br>- Analyst<br>- Union/Non Union<br>• FTE change<br>- Full time/Part time<br>• Inflationary pressure<br>• Customer growth<br>• New initiatives<br>• Safety requirements<br>• New regulation<br>• Economy<br>• Other |

Subsequent to completion of budget inputs by June 3rd, 2011, the EMT will start reviewing the capital, O&M, and other revenue budget on a one-on-one basis. The EMT review meetings with each individual group are scheduled to take place from the late part of June to early July. During the review meeting, departments are required to establish the reasonableness of their budget while ensuring sustainability. The analysis template should be submitted to the Budgets group two days prior to the EMT review meetings which will be used as a tool to facilitate the review process.

Once the budget is approved by the EMT, departments are required to prepare O&M and capital pre-filed evidence for 2013 rate case application. Regulatory department will provide further guidance in this regard under separate cover at later date.

**7. New Workforce Planning (WFP) Process**

Position Management process requires the budgeted position creation process to align with HR best practices. In order to do this, alignment is needed between the West, East, and the South to ensure the same data is collected, and the enterprise is adhering to a standardized set of guidelines. Implementation of these standards enterprise-wide for the 2011 budget cycle will ensure that people data supports an effective and high quality position management process in 2012 and 2013.

To implement the new process, managers who use the template to budget labour cost are required to fill out all the following columns for new positions (vacancies):

| | |
|---|---|
| 1. Employee name | Existing field (see comments below) |
| 2. Salary | Existing field |
| 3. Job Title | Existing field |
| 4. Department ID | Existing field |
| 5. Permanent or Temporary | New field |
| 6. Part time or Full time | Existing field |
| 7. Supervisor | Existing field |
| 8. Start date | New field |
| 9. Recruitment difficulty | New field |
| 10. End date for Temporary | New field |

The employee name for new positions should be entered as "**vacancy**" all in lower case. The standard text in the name field will streamline the data extract from Khalix. For specific requirements, please refer to Appendix C: Operations and Maintenance, FTE/Labour Budget.

Enbridge Inc. HR has set forth a consistent enterprise-wide definition for permanent and temporary vacancy in the following chart. Please note that **maternity leave is not treated as vacancy**.

| **Permanent Positions** | |
|---|---|
| Permanent (regular) Position | A position that requires a full or part time employee for an indefinite period of continuous employment.<br><br>Please note that new graduate positions are considered permanent (regular) positions and must be budgeted for. |
| **Temporary Positions** | |
| Temporary Position | A position that requires a full time salaried employee, typically for a period of 12 months or less.<br><br>**Please note that summer students working full time hours are considered temporary employees**. |
| Casual Position | A position that requires an hourly paid employee for a period of 12 months or less. These employees are typically not on a set schedule and work when contacted or requested. |
| Co-op Position | A position that requires a full time student for a 4, 8 or 12 month term. |
| **Contractor Positions** | |
| Provisioned Contractor | Individuals who operate independent businesses under corporations, trade names or sole proprietorships, who are retained by Enbridge to provide specialized technical, professional, or administrative services for a specific duration or project, where Enbridge would otherwise hire or assign employees to perform those roles or services. Where Enbridge has decided to outsource a function or service (e.g. TAB, Tier I Help Desk Support, etc.), **these roles should not be included on your workforce plans.** |

**8. Affiliate Transactions**

The costs and revenues related to affiliate transactions contained in your department should be consistent with the Enbridge Inc. cost allocation policy and the OEB's Affiliate Relationships Code. It is the individual department's responsibility to inform and receive acceptance of the budgeted amounts from their counterpart at the Enbridge affiliate.

The standard template will be distributed to departments in May. The Finance budgets group will collect the affiliate recovery budget by **June 15th, 2011** to be used for the Corporate Cost Allocation calculation by Enbridge Inc.

## 9. Budget Contacts

| Subject Matter | Contact | Phone |
|---|---|---|
| Khalix technical support | Lenny D'Alessandro | 416-758-4362 |
| Salary allocation rules<br>• Operations<br>• PI&S<br>• BD&CS | <br>• Andy Grbic<br>• John Briggs<br>• Lorraine Kennedy | <br>• 613-748-6792<br>• 416-495-5898<br>• 416-495-6119 |
| O&M in general | Asha Patel | 416-495-5876 |
| Capital in general | • Linda Au<br>• Debbie Kelly | • 416-495-5245<br>• 416-495-5280 |
| BVA Review | Iftikhar Abbasi | 416-753-7473 |
| Budget in general | Raymond Lei | 416-495-3927 |

# APPENDIX A
# TIMETABLE

## 2012 and 2013 Budget Timetable

| Major Events for EGD Departments | 2011 Key Dates |
|---|---|
| 1. Khalix EnSight opens #1 for Budget Input (Labour, Other O&M, Capex, FTEs) | 2-May |
| 2. All business cases submitted for BVA review | 15-May |
| 3. Khalix EnSight closes for Budget Input | 3-Jun |
| 4. Finance consolidate O&M, Capex, FTEs, and other revenue #1 | 6-Jun |
| 5. Departments analyze O&M, Capex, and FTEs | 6-Jun |
| 6. EMT review of O&M, Capex, Other revenue, and FTEs | Jun 21 -Jul 11 |
| 7. Khalix EnSight opens #2 for changes stemming from EMT review | 11-Jul |
| 8. Finance consolidate O&M, Capex, FTEs, other revenue #2 | 18-Jul |
| 9. EMT approval of O&M, Capex, Other revenue, and FTEs | 25-Jul |
| 10. Depreciation and property taxes for 2012 and 2013 | 2-Aug |
| 11. EMT #1 review of EGD initial first cut 2012 and 2013 Budgets | 8-Aug |
| 12. Distribution margin for 2012 and 2013 | 8-Aug |
| 13. EMT #2 review of EGD 2012 and 2013 Budgets | 15-Aug |
| 14. EMT approval of EGD 2012 and 2013 Budgets | 22-Aug |
| 15. Departments start to prepare pre-filed evidence for 2013 rate case | 23-Aug |
| 16. The Company files 2012 IRM rate case application to OEB | 1-Oct |
| 17. The Company files 2013 rate case application to OEB | 7-Nov |

# APPENDIX B
# STRATEGIC OBJECTIVE

## Gas Distribution Vision & Strategies

To become the leading energy distribution and services company in North America.

1. Ensure Best Employer Status
2. Achieve & Maintain Top Decile Safety Performance
3. Enhance Governance, Integrity and Transparency in All Business Processes
4. Protect & Enhance the Enbridge Brand with Customers & External Stakeholders
5. Grow the Business Earnings by 8% Annually

The key strategic objectives should be considered as each department prepares its volumetric, revenue, capital and operating and maintenance expense budgets.

# 1. ECONOMIC AND MARKET ASSUMPTIONS

## ECONOMIC OUTLOOK

(Ian McLeod, 416-495-6139)

The Economic and Market Analysis Department has prepared its **2011 Winter Economic Outlook** which is attached along with the Budget Letter. The document provides a review and forecast of economic conditions expected to prevail in the national, provincial and franchise economies for the 2012 calendar year. Forecast tables for the main economic variables, including housing starts and inflation, are available in this document.

The Economic Outlook is provided as background information to supplement your community knowledge and to ensure that a single, consistent view of macroeconomic trends is adopted across the Company for budgeting and planning purposes. More detailed forecasts for the residential and industrial sectors are also available to assist in the budget process and can be obtained by contacting Lee-Ann Lavergne (416-495-5256).

Key economic assumptions for O&M and Capital as of April 2011 are:

| | 2011 Forecast | 2012 Budget | 2013 Budget |
|---|---|---|---|
| Inflation factor – GDP IPI FDD | 0.72% | 1.70% | 1.73% |
| Customer Additions | 37,046 | 37,927 | 38,896 |

# 2. OPERATIONS AND MAINTENANCE

(Asha Patel, 416-495-5876)

### FTE/Labour Budget

Departments are required to input the FTE budget in the Permanent/Temporary/ Permanent Vacancy/Temporary Vacancy module in Khalix Ensight for all 3 of the following time period:

- 2011 Forecast (FYR11)
- 2012 Budget (BYR12)
- 2013 Budget (BYR13)

The FTE budget in the Capital/O&M module will be automatically calculated based on the server rules which were submitted to Lenny D'Alessandro.

| FTE MODULE | | |
|---|---|---|
| Union/Non-Union | New | • No input required as it will be automatically populated |
| Vacancies | New | • Vacancies are to be budgeted by permanent and temporary |
| **LABOUR INPUT TEMPLATE** | | |
| Labour Seeding | Existing | • Seeded with employee details and salary information from PeopleSoft as of **April 15th, 2011** |
| Salary Increase 2012 Budget (programmed in Khalix) | Existing | • 3.3% non-union effective April 1st<br>• 2.0% and 1.5% union effective January 1st and July 1st respectively |
| Salary Increase 2013 Budget (programmed in Khalix) | Existing | • 3.3% non-union effective April 1st<br>• 2.0% and 1.0% union effective January 1st and July 1st respectively |
| Vacancies | New | • All fields are to be filled out similar to how an existing employee is budgeted For the Employee Name field only enter the word **vacancy** |
| Inputs for Workforce Planning (only required for **vacancy**) | New | • Employee name – vacancy<br>• Salary<br>• Job Title<br>• Department ID<br>• Permanent or Temporary<br>• Part time or Full time<br>• Supervisor<br>• Start Date<br>• Recruitment Difficulty – use fixed three options - easy/moderate/difficult<br>  ○ **easy** – if the position can be filled internally<br>  ○ **moderate** – if the position needs to be filled externally<br>  ○ **difficult** – if the position requires a specific skill set to be qualified<br>• End Date for Temporary |

**Inflation**

- Items which need to be adjusted for an inflationary increase should use GDP IPI FDD of **1.70%** and **1.73%** as the inflation index for 2012 and 2013 respectively (Refer to Economic Outlook).

**Vacancy credits**

- Vacancy credits should be incorporated in the budget at **2.25%** of gross salary at the cost centre level which is mandated by HR. Please use the natural account **# 60141** (vacancy credit) to budget the credit amount. Since this is a unique account for vacancy credits please do not budget anything else in it.

**Natural Account**

- Budget input should be made by natural account and ensure that there is no mismatch between where the budget and actuals are recorded.

**Monthly profile**

- Budgets should be prepared by monthly profile that reflects the anticipated timing of O&M expense. Budget variances due to timing should be eliminated to the extent possible.

**Labour Budgeting**

- Ensure monthly profile of labour costs reflects the timing of anticipated changes in staffing levels and promotions.

- All increases in FTEs must be approved by your EMT member.

**Salary & Wages Increases**

- The two 2011 increases: 2.0% on January 1st and 1.5% on July 1st for union employees have been taken into consideration and programmed into Khalix since the April 15th, 2011 salary data seeded from PeopleSoft didn't reflect the two increases.

- Salary increases for any employee changes made during the current budget cycle must be adjusted manually.

- Salary assumptions will be continually reviewed by Human Resources and may be changed if appropriate.

## SPECIFIC EXPENSE GUIDELINES

| Expense Type | Budget Structure | Account | Accountability | Guidelines |
|---|---|---|---|---|
| STIP | Centralized | | HR (Sheila Trozzi/Daniela Perciasepe) | |
| Special Labour | Centralized | | HR (Mary Lee) | Based on EMT discretion and departmental needs |
| Employee Benefits | Centralized | | HR (Sheila Trozzi/Daniela Perciasepe/Mary Lee) | |
| Employee Services and Development (EGD Wide) | Centralized | | HR (Mary Lee) | Ex. Internal courses, exec. Development, tuition aid, etc. |
| External Legal Fees | Centralized | | Legal (Amy McGregor) | Based on inputs fromdepartments |
| Reprographics | Centralized | | IT (Bimal Desai) | |
| Telecommunications | Centralized | | IT (Bimal Desai) | |
| Postage | Centralized | | Facilities (Mary Lee) | Customer Care excluded |
| Employee Recognition (Christmas Party) | Centralized | | HR (Mary Lee) | |
| Employee Training (job-specific) | Decentralized | P6040 | Departments | E.g. External conferences, job-specific courses |
| Corporate Cost Allocations | Decentralized | A74002 A74007 | Departments | Allocated to depts based on the amount provided by EI |
| Recognition | Decentralized | A60411 | Departments | $60/employee for recognition initiatives |
| Affiliate Recoveries | Decentralized | A79966 | Departments | Template will be distributed for tracking |

# 3. CAPITAL EXPENDITURES

## CAPITAL PLANNING PROCESS

(Iftikhar Abbasi, 416-753-7473)

The Portfolio Management Committee ("PMC") welcomes capital users in the fifth year of the planning process. The Capital Planning process at the Company has progressed through gradual improvements since 2007. The evolution of the process continues in 2011 as we learn from the past and incorporate those lessons in our systems, structures, and practices. The importance of collection of relevant and reliable information and thorough evaluation of projects remains the same this year. The team aims to design an optimum capital portfolio that meets the budgetary constraints while maximizing the expected return on total capital and achieving the various regulatory and organizational goals.

In the last year's planning process, sub-portfolio controllers were made accountable for spearheading the business case development process. That change strengthened project evaluation and speeded up the portfolio approval process. The introduction of the COMMS-EnBIT software resulted in consistency in capital inputs. These changes have further streamlined the Company's capital planning.

As the Company gets ready to file its IR rebasing application in 2011, capital users will be required to prepare budgets and business cases for two years i.e. 2012 and 2013. The business case template has been enhanced to enable users to develop their 2012 and 2013 cases using the updated BVA template. This year, EnBIT software has been further upgraded to include Distribution Asset Management projects reducing the need for frequent reconciliation between Khalix and CapMan.

The PMC has been updated this year based on changes in employees' roles and responsibilities. The following table provides the updated PMC information.

| Sub-Portfolio | Role | Accountability |
|---|---|---|
| Revenue Generation – Customer Adds | Manager | Paul Green |
| | Controller | Faheem Ahmad |
| Revenue Generation - Other | Manager | Sagar Kancharla |
| | Controller | Lorraine Kennedy |
| System Integrity | Manager | Lloyd Chiotti |
| | Controller | John Briggs |
| Storage | Manager | Jim Sanders |
| | Controller | Brad Pilon |
| Information Technology | Manager | Henry Wong |
| | Controller | Tunde Adesipo |

| | | |
|---|---|---|
| Logistics & Support | Manager | Nizam Ali |
| | Controller | Walter Carvajalino |
| Indirect Overheads | Manager | Barry Yuzwa |
| | Controller | Debbie Kelly |

**2012 - 2013 Portfolio Management - Timelines and Milestones**

The timelines for the 2012-2013 Portfolio Management process have been established in accordance with the timelines for IR rebasing application expected later this year.

| Timelines | Major Milestones |
|---|---|
| March 1st – 30th | Establish Targets for System Integrity and Customer Adds |
| Apr 1st – May 13th | Business Case Creation |
| May 15th – Jun 7th | Business Case Review |
| Jun 8th – 30th | Portfolio Optimization |
| Sep 30th | Communicate Project Approvals |
| Nov 1st – Dec 20th | Create and Approve AFE's |

Given the capital intensive nature of the gas distribution industry, Capital Portfolio Planning is a key priority for the Company. The shortened timelines and anticipated higher workload pose a challenge for the portfolio management team and capital users. The portfolio team hopes to meet the challenge through better planning and coordination.

## CAPITAL BUDGET

(Debbie Kelly, 416-495-5280; Linda Au, 416-495-5245)

## CAPITALIZATION POLICY

**Capital vs. Expense General Guidelines**

An expenditure that is to be capitalized, as a capital asset must meet all three general criteria listed below:

1. Provide an economic life of more than **one year** through their use in the production of supplying services to customers, for administrative purposes, or for the development of construction, maintenance or repair of other capital assets

2. Capable of performing an operating function or providing a service on a continuing basis (as opposed to the item being acquired for sale in the ordinary course of business as is the case with gas inventory)

3. Must cost more than a set minimum amount. (Note: A minimum cost as indicated in chart below is required for an item to be capitalized unless the item is part of a larger budget appropriation that is classified as capital in which case the item should be capitalized as part of the larger appropriation).

**Minimum Cost Limits for Capitalization**

| Description | Account | Minimum Capitalization Amount |
|---|---|---|
| **Fleet and Equipment** | | |
| Small tools and Work Equipment | 0486 | ≥$500 |
| Construction Trucks | 0484 | All |
| Heavy Work Equipment | 0485 | ≥ $1000 |
| **Facilities** | | |
| Structures and Improvements | 0472 | ≥ $200 |
| Office Furniture and Equipment | 0483 | ≥ $500 |
| Lease Hold Improvement | 0482 | ≥ $200 |
| **NGV Compressor Equipment** | | |
| Compressor | 0476 | ≥ $300 |
| **IT** | | |
| Computer Equipment | 0490 | ≥ $500 |
| Communication Equipment | 0488 | ≥ $200 |

The cost of a capital asset should include the purchase price and other costs, necessary for its intended use at the intended location. The other costs include installation, design, engineering fees, legal fees, survey costs, site preparation costs, testing and preparation charges, freight charges, transportation, insurance costs and duties. Sales taxes other than GST should be included where applicable.

In addition to meeting the three general criteria, expenditure should fall into at least one of the three additional categories identified below in order to be classified as Capital.

1. Expenditures on assets, including newly purchased items, extensions or alterations to the existing assets, which are required to increase the service capacity. (Examples: ROI/Capacity/Customer Additions; ROI/Capacity/Other; Non Customer on Main (Non-Com), Oversizing)

2. Expenditures on assets, including newly purchased items, extensions or alterations to the existing assets, which are required to increase the useful life of an item beyond that contemplated in depreciation provisions. (Examples: Replacing floors, replacing a roof, new heating/cooling system, structural changes to buildings, significant improvements to leased property, reconditioning machinery, replacing car/truck engine, overhauling worn out car/truck, rebillable distribution plant related projects, distribution plant replacement projects with

expenditures greater than $1,000)

3. Expenditures for assets including, extensions, alterations, renovations, improvements, or replacement to the existing assets to improve the profitability of the company (Net cash flow ≥ value of the asset). (Example: ROI/Other-Facilities, programs, purchases that provide efficiencies, increased revenue and/or avoided costs)

**Property Taxes and Other Carrying Costs**
In general, interest charges, property taxes and other carrying costs related to fixed assets should be expensed as incurred. Property taxes should only be capitalized when they relate to new projects that take a year or more to complete.

**Company Employees and Overheads**
EGD allocates overheads to projects in various manners. The IT groups and the Engineering/Operations groups each utilize their own methodologies. Both methodologies refer to direct labour in the allocation. Certain ongoing overheads may be capitalized if approved by the OEB (i.e.: capitalized administrative and general overhead and interest during construction).

Administrative overhead to be capitalized and interest during construction will be calculated by the Capital Budgets and Accounting group and will be added to each Region's/Department's budget after it has been submitted.

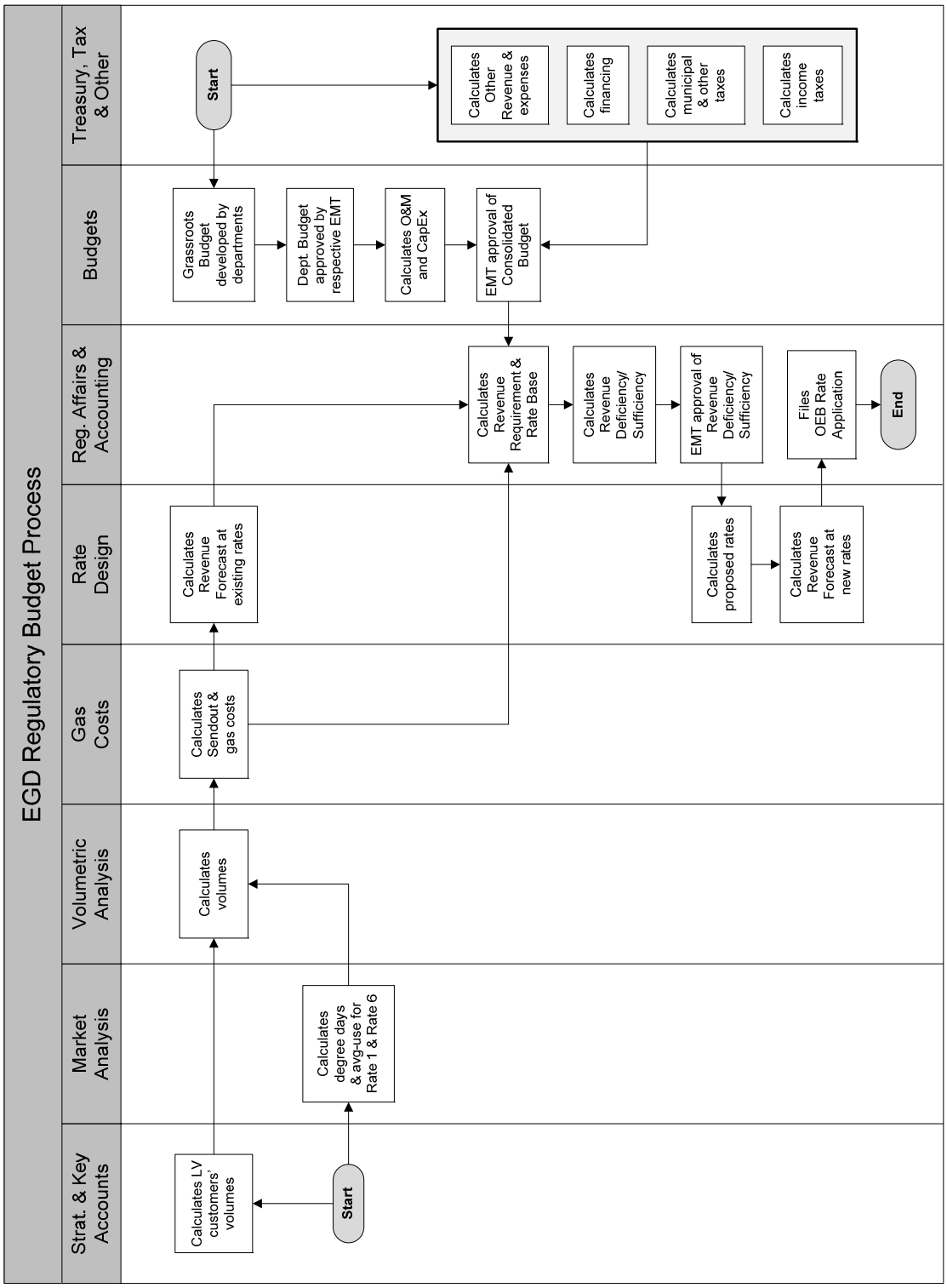
**Computer Hardware**
Computer hardware is capitalized in accordance with the above general guidelines.

**Intangible Assets**
This relates primarily to Information Technology Software. Commencing on page 42 of the Accounting Policy Framework: Capital Expenditure, there is detailed guidance on the criteria required to capitalize intangible assets, including computer software.

**Timing**
It is important to be as precise as possible with respect to the timing of capital expenditures. Attention to timing in the capital budget minimizes the potential for budget variances in the areas of revenue, expenses, interest, depreciation, and income tax (re: CCA) which occur simply because of project timing. In addition to expenditure timing where possible, please indicate what date you expect a project to be in service.

**Projects Greater Than $500K**
Projects in excess of $500K are tracked for the regulatory reporting purposes. Please keep this in mind as the Capital Budget group will be soliciting this information from you.

**Reference Material**
Accounting Policy Framework: Capital Expenditure can be found within the Finance section of the Policies and Procedures area of eLINK.




Witnesses: S. Kancharla
R. Lei

# APPROVAL PROCESS

1. The purpose of this evidence is to present the approval process for the 2013 Budget.

2. The budget approval process is described in the Budget Letter, which is filed as Exhibit A2, Tab 2, Schedule 1. The Budget Letter set clear guidance and expectations on how the budget should be formulated. It is emphasized that the budgets should be built on a sustainable, acceptable, and defendable basis.

3. The individual departments used a bottom-up approach to develop their 2013 budgets in accordance with their 2013 operating model, strategic objectives, budget assumptions and guidelines. These budgets were then reviewed and approved by the Executive Management Team (the "EMT") member for each department before they were submitted to Finance. The Finance group conducted individual budget review meetings with each member of the EMT and other key department leaders, in order to ensure that the budget was reasonable and accurate; tied back to the Company's overall strategies; and met the EMT's expectations. The 2013 Budget, in total, was then reviewed and approved by the EMT. This process ensured that the budget had approval and commitment from all levels of management within the Company.

4. The flow chart of the budget process can be found at Exhibit A2, Tab 2, Schedule 2.

Witnesses: S. Kancharla
R. Lei

# CHANGE IN ACCOUNTING METHODOLOGY – OTHER POST-EMPLOYMENT BENEFITS ("OPEB")

1. In this application, Enbridge is requesting the Board's approval to recover OPEB expense on an accrual basis calculated in accordance with USGAAP rather than on the cash basis commencing January 1, 2013 in a manner appropriate for a rate regulated entity.

2. Further, Enbridge is requesting the recovery of the proposed Transition Impact of Accounting Changes Deferral Account ("TIACDA") in the amount of approximately $90 million over a 15 year period.

## Background for OPEB

3. The most significant post-employment benefits provided to employees are pension related benefits. In addition, employees are often entitled to non-pension related benefits. These are commonly referred to as OPEB. Unlike pensions, they are not typically pre-funded by employers. Enbridge does not set aside any funds for the future payouts but rather it is on a pay-as-you-go basis.

4. For Enbridge employees, OPEB expenses include items such as supplemental health plans, dental plans, health spending accounts, and life insurance coverage for qualifying retirees. Please see Appendix 1 for details of the OPEB plans that Enbridge offers its employees after they are retired.

5. These benefit plans are considered part of the employee's compensation package. Enbridge must provide these benefits to an employee in future periods relating to service provided by the employee in the current period.

Witnesses: K. Culbert
J. Jozsa

6. OPEB payouts for current employees do not occur until the future when the employees are retired. Therefore many assumptions must be used to calculate the OPEB liability and expense. This involves actuarial analysis of future costs utilizing management's assumptions, which are discounted to present value. Enbridge utilizes the services of Mercer (Canada) Limited ("Mercer") for the estimate of the future OPEB liability and expense. Some of these assumptions utilized include discount rates, mortality rates, and estimated medical and drug costs.

Accounting Background for OPEB

7. Historically, the accounting for OPEB was straight forward for regulatory and financial reporting. The cash contributions, equal to benefit payments for retired employees, that Enbridge was required to contribute to meet its OPEB liabilities was the amount that was expensed on the income statement.

8. For fiscal periods beginning on or after January 1, 2000, Canadian companies were required to adopt accrual accounting for OPEB for external reporting purposes pursuant to Section 3461 of the CICA Handbook – *Employee Future Benefits*. However, Enbridge and other rate regulated utilities in Canada were permitted to record OPEB on a cash basis with no recognition of the OPEB liability. Accordingly, there was no difference in the methodology for calculating OPEB expense between external reporting and regulatory purposes.[1]

9. In 2001, Enbridge first disclosed in its financial statements the unrecorded accrued OPEB liability. The OPEB liability balance at September 30, 2001 was approximately $55 million (excluding the impact of the Transitional Obligation noted

[1] Note that OPEB expense for regulatory purposes would be based on expected OPEB costs whereas the OPEB expense on the financial statements would be based on actual cash payments.

in paragraph 10), which was the first year-end in which the new provisions were applicable. See Appendix 2 for a historical continuity of the OPEB liability from 2001 to 2010.

10. Transitional Obligations occur on the adoption of the accrual method of accounting for OPEB. The Transitional Obligation represents the cumulative difference between accounting treatments up to the implementation date of the accrual method (i.e., October 1, 2000). This Transitional Obligation was to be amortized over 15 years (ending in 2015 if CGAAP would have continued) for accrual accounting for OPEB, representing the expected remaining average service life of employees at that time. There was no impact to Enbridge from an external reporting perspective as it was permitted to continue utilizing cash accounting for OPEB. The Transitional Obligation set up as of October 1, 2000 was approximately $50 million , with an unamortized amount of $16 million as at December 31, 2010. See Appendix 3 for a historical continuity schedule of the Transitional Obligation.

11. Effective January 1, 2009, the CICA removed the rate regulated entity exemption noted in paragraph 9 above and Enbridge and other utilities began to record as a regulatory asset, the cumulative difference in OPEB costs calculated under the Accrual method and OPEB costs for regulatory purposes[2]. The offsetting regulatory asset is not a Board Approved account but rather recognition of the difference between the existing regulatory approved method and amounts that are required costs which are reasonably recoverable regardless of differences in regulatory versus accounting recognition.

[2] Deletion of *CICA handbook paragraphs 1100.34-.35* to remove the exemption from the requirement to apply this Section to the recognition and measurement of assets and liabilities arising from rate regulation

12. The impact of the removal of this exemption for rate regulated entities in Canada was that Enbridge had to record on the income statement an OPEB expense on an accrual basis which was then offset by the impact of recording a regulatory asset. On a net basis however, the net impact of these entries was that the OPEB expense reflected in the income statement equaled what would be recorded using the cash basis for external reporting, consistent with the regulatory methodology. The balance sheet reflected the recognition of the OPEB liability along with the offsetting regulatory asset. The OPEB liability balance at December 31, 2009 and 2010 was approximately $63 million and $68 million respectively[3]. Enbridge also disclosed the OPEB expense calculated on an accrual basis.[4]

OPEB accounting: CGAAP vs USGAAP

Income Statement

13. As noted, OPEB expense calculated in accordance with CGAAP on an accrual basis commenced in 2009, although the impact of the offsetting regulatory asset resulted in an OPEB expense equal to the cash basis. Accrual expense under CGAAP for OPEB plans is typically made up of the following elements:
    a) Current Service Cost
    b) Interest cost
    c) Transitional Obligation amortization
    d) Actuarial (loss)/gains amortization

[3] See Appendix 1
[4] All amounts in this document refer to Enbridge alone and exclude any amounts relating to its wholly owned subsidiary, St. Lawrence Gas Inc. Accordingly, amounts will not directly tie into Enbridge's external consolidated audited financial statements. See also Appendix 2 for a reconciliation of amounts for the 2009 and 2010 fiscal periods.

14. Similar to CGAAP, USGAAP does not permit the cash basis to be used as a basis of accounting for OPEB. However, while an offsetting regulatory asset can be set up in CGAAP, in USGAAP there are only limited circumstances in which an offsetting OPEB regulatory asset can be recorded pursuant to ASC 980-715-25, the main criteria being Board approval for deferral and future collection.

15. Accrual expense is required for USGAAP pursuant to ASC 715-60-35-7[5]. The accrual expense under USGAAP is calculated very similarly to CGAAP, with two exceptions. First, there is no concept of Transitional Obligation relating specifically to CGAAP conversion under USGAAP so there is no related amortization amount included in USGAAP expense. The unamortized portion was written off to Retained Earnings from a USGAAP perspective. Second, unamortized gains and losses are not directly charged to earnings but rather to Other Comprehensive Income. Unamortized gains and losses are charged to Other Comprehensive Income and amortized into earnings over the expected average remaining service life of employees.

16. USGAAP expense for OPEB plans will typically consist of the following elements:
    a) Current Service Cost
    b) Interest cost
    c) Actuarial (loss)/gains amortization

17. The calculation of accrual expense is similar in both USGAAP and CGAAP. Under CGAAP, accrual expense included the amortization of the Transitional Obligation, which has been written off for USGAAP purposes. Historically, the annual

[5] Accrual accounting would also be required in IFRS

amortization has been approximately $3 million and would be fully written off by 2015 if CGAAP had continued to exist.

Balance Sheet

18. As noted in paragraph 12 above, Enbridge's balance sheet has reflected an OPEB liability and an offsetting regulatory asset since the beginning of 2009. Previous to that, the amounts were only disclosed in notes to the financial statement. The OPEB liability recorded on the balance sheet was comprised of the sum of the following elements:
    a) Opening OPEB Accrued Benefit Obligation
    b) Current Service Cost - accounts for present value of the benefits accrued by current employees during the current year
    c) Interest Cost - accounts for the cost of increase in present value of existing OPEB liability due to passage of time
    d) Actuarial loss (gain) - accounts for the change in the OPEB liability as a result of changes in actuarial assumptions (i.e. discount rates, mortality rates, etc.) and plan experience
    e) Benefits paid – cash amounts paid out by Enbridge
    f) Unamortized Transitional Obligation – see paragraph 10
    g) Unamortized net actuarial loss/(gain) – difference between actual experience and assumptions not yet recognized in the balance sheet liability

19. Enbridge's OPEB liability was approximately $68 million[6] as of December 31, 2010 for CGAAP purposes.

[6] See Appendix 1

20. For USGAAP purposes, a regulatory asset cannot be recorded as noted previously without future recoverability substantiation. The OPEB liability recorded represents the funded status of the plan (i.e., OPEB Accrued Benefit Obligation)[7]. There are no plan assets to take into account. Enbridge's OPEB liability was approximately $80 million[8] as of December 31, 2010 for USGAAP purposes, the difference relating to the exclusion of the unamortized Transitional Obligation and unamortized net actuarial gain.

21. For USGAAP purposes, the OPEB liability will include all elements as per CGAAP with two exceptions.
    a) Unamortized Transitional Obligation - this amount has been written off to Retained Earnings upon conversion to USGAAP.
    b) Unamortized net actuarial loss/(gain) – this amount now is part of Accumulated Other Comprehensive Income.

<u>Accrual Basis of Accounting for OPEB</u>

22. As noted, Enbridge proposes to adopt the accrual method of accounting for OPEB costs for regulatory purposes effective January 1, 2013.

23. There are several benefits of adopting the accrual method for OPEB accounting, including:
    i) OPEB accounting would then be in accordance with the accounting principles utilized for external reporting purposes (i.e. USGAAP), and there would be reduced complexity for users of the Enbridge's financial statements. It is Enbridge's view that there is no reason for different

[7] ASC 715-60-25, *Defined Benefit Plans, Other Post-Retirement - Recognition*
[8] See Appendix 1

regulatory accounting treatments of OPEB other than any potential desire to defer rate impacts.

ii) Harmonization with many other utilities' method of accounting for OPEB in Ontario, including Union Gas, Ontario Power Generation, Hydro One and Toronto Hydro. This would assist in benchmarking against other utilities.

iii) From an equity perspective, it makes more sense for the OPEB expense to be attributed to the periods in which the employees are providing services rather than burdening the full cost to future customers. According to the CICA handbook, "*The objective of accounting for the cost of Employee Future Benefits is to recognize a liability and a cost in the reporting period in which an employee has provided the service that gives rise to the benefits*"[9]

iv) Harmonization with the concept of matching costs to the period in which they are earned rather than when they are paid, similar to compensation related costs such as Stock Based Compensation ("SBC"). Enbridge is of the view that the Board's comments relating to SBC, for example, would also apply to OPEB where *"GAAP accounting treatment as provided by the CICA Handbook, which uses the vesting time period as the basis of matching, is a rational, systematic and appropriate manner to match the costs of the ISO* [Incentive Stock Option] *grants to time periods"*[10]*.*

24. Mercer has estimated[11] the cash expense and accrual expense under USGAAP for OPEB to be the following in $millions, based on current market assumptions:

[9] *CICA Handbook Section 3461, paragraph .002*
[10] EB-2010-0042, Decision and Order "Stock-Based Compensation expenses in the 2009 Earnings Sharing Calculation" dated November 10, 2010
[11] See Appendix 4 (page 3) and Appendix 5 (page 6)

| | Cash Basis | Accrual Basis |
|---|---|---|
| 2013 | 3.8 | 5.5 |
| 2014 | 4.0 | 5.5 |
| 2015 | 4.3 | 5.5 |
| 2016 | 4.6 | 5.5 |
| 2017 | 4.8 | 5.4 |

25. It is Enbridge's belief that future annual increases in the cash payments as a result of increased costs of OPEB will exceed the annual increases as calculated under the accrual method.

26. Mercer has also provided[12] a sensitivity analysis on the impact to Enbridge under the accrual method if there is a +/- 1% change to the yield curve relative to current market assumptions. The impact to USGAAP accrual expense[13] is as follows in $millions:

| | + 1% | - 1% |
|---|---|---|
| 2013 | 0.0 | 0.6 |
| 2014 | 0.0 | 0.5 |
| 2015 | 0.0 | 0.4 |
| 2016 | 0.1 | 0.3 |
| 2017 | 0.2 | 0.3 |

[12] See Appendix 5 (page 9)
[13] This rate impacts the discounting of the liability and does not impact the short-term cash payments

Witnesses: K. Culbert
J. Jozsa

27. EGD has listed the benefits above, and demonstrated that adjusting to the accrual method impacts only the timing of when amounts are collected from ratepayers and that there is no significant annual difference in expense, and as a result, Enbridge proposes to recover OPEB on an accrual basis.

Transition Impact of Accounting Changes Deferral Account

28. In its 2012 rates application EB-2011-0277, Enbridge requested approval to establish a 2012 Transition Impact of Accounting Changes Deferral Account ("TIACDA"). The purpose of this account is to recognize and record the financial impacts that will occur in 2012 in relation to Enbridge's required transition away from CGAAP.

29. Enbridge estimates that the amount to be charged to the TIACDA to be approximately $90 million and comprised of the following components:
    a) Unamortized Transitional Obligation as of December 31, 2010 of approximately $16 million and the cumulative difference between the cash and accrual method of approximately $68 million as of December 31, 2010 for a total of $84 million[14]. These amounts were previously included in the OPEB regulatory asset which had to be written off once CGAAP was no longer an accounting methodology option.
    b) Adjustments to a) above to reflect the difference between the cash and accrual method under USGAAP in 2011. This is estimated to be approximately $3 million.
    c) The difference between the cash and accrual method under USGAAP for 2012. This is estimated to be approximately $3 million.

[14] The approximate $4 difference between $84 million and the $80 million per paragraph 20 is primarily a result of the impact of $4 million of actuarial gains charged to Other Comprehensive Income.

30. Enbridge recorded a Retained Earnings adjustment relating to the write-off of the OPEB regulatory asset upon the discontinuation of CGAAP[15]. This amount of the write-off was adjusted by the removal of the unamortized Transitional Obligation which is not permitted in USGAAP.

31. The amounts written off to Retained Earnings are mandatory with the discontinuation of CGAAP as they no longer qualify for asset treatment. These amounts are liabilities of Enbridge relating to services provided in the past by employees. These amounts will be paid out in the future, to which the OPEB liability relates as recorded on the balance sheet.

32. Enbridge's balance sheet (and accompanying financial ratios) have been negatively impacted by the discontinuation of CGAAP as it relates to this issue and the related retained earnings impact. Under CGAAP or USGAAP, the amounts are legitimate recoverable business costs and the balance sheet should not be adversely impacted.

33. If the TIACDA amount is approved for recovery, Enbridge will be able to reinstate the amounts written off for external financial reporting purposes given the TIACDA would then be reinstated as an asset.

34. Enbridge is requesting recoverability of the approximately $90 million to be recovered commencing with 2013. There is no accounting pronouncement which prescribes the recovery period for this type of amount although Enbridge does not expect full recovery in 2013.

[15] See A1-6-2 Appendix 2 where this adjustment is disclosed on an after-tax basis.

35. An amortization period alternative would be the current expected average remaining service life of employees of 12.7 years (rounded to 13 years). Alternatively, an option would be to amortize over the amortization period of 15 years , which was utilized for the amortization of the Transitional Obligation originating in 2000. When Union Gas and Newfoundland Power converted from cash to accrual basis, they utilized amortization periods of 17 and 15 years respectively[16].

36. Enbridge is of the view that a 15 year amortization period is reasonable because it prevents rate shock, similar to length as other utilities who converted to the accrual method and is similar to the expected average remaining service life of employees. As a result, Enbridge is requesting the continuance of the TIACDA for a period of years to provide for the carry-over of the unrecovered amounts until complete recovery is achieved.

37. In addition to the TIACDA impacts proposed by Enbridge for 2012, the following TIACDA treatment for 2013 and future years are proposed:
    a) If Enbridge calculates OPEB expense in accordance with the accrual method under USGAAP for regulatory purposes, there will be no adjustments made to the TIACDA;
    b) If Enbridge is required to calculate OPEB expense in accordance with the cash method for regulatory purposes, there will be a charge for the difference between the cash method and the accrual expense calculated will need to be recorded in accordance with USGAAP.

[16] See Union Gas RP-1999-0017 for approval of adopting of accrual method and Union Gas' 2000 Audited Financial Statements for disclosure of the amortization period. In addition, see Newfoundland Power Order No. P.U. 31(2010).

ENBRIDGE

# Company Benefit Program for Retirees

Once you retire from the Company, you will be receiving an Enbridge Gas Distribution Inc. pension, and you will also be eligible for health care benefits and, in some cases, for certain other benefits as well.

**This booklet gives you important information you need as a Company pensioner, and describes the other benefits to which you are entitled. Please keep this in a safe place.**

## Your Enbridge Gas Distribution Inc. Company Pension

Now that you are receiving a Company pension, there are a few important things you need to know.

## Pension Increases

After you retire, the Pension Plan will continue to protect your pension from some of the effects of inflation. Specifically; your pension will be increased on the second December 1st after you retire, and on every December 1st thereafter. Your pension in respect of Contributory Service with the Enbridge Gas Distribution Plan will be indexed at 55% of the increase in the Consumer Price Index for the year ending the prior August 31st, to a maximum annual increase of 5%.

Your pension in respect of the Non-Contributory Service with the Enbridge Gas Distribution Plan will be indexed at 50% of the increase in the Consumer Price Index for the year ending the prior August 31st.

For example, if you retired on July 1, 2002 your first pension increase would occur on December 1, 2003. If the increase in the Consumer Price Index for the year ending August 31, 2003 is 2%, your

Contributory Service pension would be increased on December 1, 2003 by 55% of 2%, or 1.1%. Your Non-Contributory Service pension would be increased on December 1, 2003 by 50% of 2%, or 1%.

Since your CPP/QPP pension and your Old Age Security pension are also increased due to inflation, the purchasing power of your total retirement income is substantially protected.

## Banking Information

Your pension is paid to you monthly, by direct deposit into your bank account. Income tax is, in most cases, withheld.

If you plan to change your bank, your branch, or your bank account, please contact the Human Resources Service Centre prior to the change taking place.

## Address Change

If you change your address, please notify the Human Resources Service Centre **immediately**.

## Beneficiaries

If you wish to change your beneficiary, please contact the Human Resources Service Centre. We will be able to inform you if this is permissible, and will assist you if it is.

## Death

Your spouse, beneficiary or the executor of your Estate must inform the Human Resources Service Centre immediately when you die.

Failure to do so could put your spouse or beneficiary in the awkward position of having to return any pension overpayment that they received after your death.

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### Questions?

If you ever have any questions or concerns about your Company Pension, please write, fax, email or call the Human Resources Service Centre. We will be pleased to help you.

CONTACT INFORMATION:

Phone: 416-492-4747
Toll Free: 1-800-392-8398
Fax.: 416-495-6457
Email: enquiries.payroll@enbridge.com

## Your Retiree, Group Benefits Plan

The Company is concerned about your welfare after you retire from the Company. To help protect both you and your family during retirement, the Company provides the continuation of many of your active group benefit coverages. The coverages offered to you as a retiree of the Company include:

(i) continuation of your basic life insurance coverage until you turn age 65. (Manulife Policy #GL1894)

(ii) hospital, medical and vision care plan for you and your eligible dependents. (Sun Life Contract #25113)

(iii) continuation of your active group dental plan for you and your eligible dependents until you turn age 65. (Sun Life Contract #25113)

The full cost of the retiree benefits plan is paid for by the Company.

**The following summaries of your retiree group benefits have been written in as clear and non-technical language as possible. They do not create or confer any contractual rights.**

**The complete terms of coverage are governed at all times by the provisions of the group contracts, legislation and Company policy.**

**The Company provides these plans with the intention that they will be continued indefinitely. However, the Company reserves the right to modify or discontinue any plan at any time.**

## Retiree Basic Life Insurance Plan

If you retire from the Company ***prior to turning age 65***, your active amount of basic life insurance coverage in effect on the date you retire will be continued until your 65th birthday.

Some important facts you should know about your retiree basic life insurance coverage are outlined as follows:

## Can I convert my retiree basic life insurance coverage when it ends?

Yes. You are eligible to change the lost amount of insurance, ***without submitting medical evidence,*** to one of the insurance company's individual life insurance policies. You will be responsible for the payment of the premium applicable to the individual life insurance policy.

You must elect to change your policy **within 31 days** of the date your retiree basic life insurance ends. The amount of coverage you will be allowed to convert will be determined by the group insurance contract.

Should you elect to change your retiree basic life insurance policy to an individual policy, the individual policy will take effect on the later of 31 days following the date your retiree basic life insurance coverage ended, or, the date your first premium payment is received by the insurance company.

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Should you die within the 31 days following the date your retiree basic life insurance ended, the amount of coverage you were entitled to convert will be paid to your beneficiary, regardless of whether you applied to change your coverage.

To convert your retiree basic life insurance coverage, **please contact the Human Resources Service Centre**.

If you are healthy and can pass an insurance medical, we encourage you to contact your insurance agent/broker as less expensive coverage options may be available.

## Your designated beneficiary

The beneficiary designated under your basic life insurance coverage at the time you retire will continue to apply to your retiree basic life insurance coverage. Where permitted by law, you may apply to change your designated beneficiary at any time by contacting the Human Resources Service Centre. You will be provided with the necessary forms to complete and remit to the Company in order to change your beneficiary.

Any changes in your designated beneficiary will take effect on the date written advisement is received by the Company.

***Make sure*** that your beneficiary designations are in order at the time you retire from the Company to avoid potential problems.

## Hospital Expenses

The Company retiree hospital plan covers up to the difference between the amount of the expense paid by your provincial health plan and the hospital's charge for semi-private room accommodation.

The plan also covers the cost of any ward accommodation user fees, where permitted by law. For all hospital charges related to the services of a chronic care facility of a hospital, reimbursement will be limited to a lifetime maximum of $10,000.00 per covered person.

## Medical Expenses

The Company medical plan pays **90%** of the cost of eligible expenses for you and your eligible dependents. You are responsible for the remaining **10%** of all costs up to $1,000.

After your family has incurred $1,000 in eligible claims, the Company medical plan begins paying **100%** of any additional eligible expenses.

The 90/10 co-insurance feature does not apply to semi-private hospital coverage, vision care or paramedical practitioners (i.e., chiropractic treatment and physiotherapy) of the major medical expense.

Medical coverage is subject to a maximum payment, per covered person, equal to $50,000 in any three consecutive calendar years.

You will have up to the end of the next calendar year to make claims against the balance in your Health Spending Account with Sun Life.

## Vision Expenses

The Company retiree vision care plan provides an allowance towards the cost of the purchase of glasses, contact lenses and eye examinations. The vision care plan is not subject to an annual deductible.

## Medical expenses covered by the plan

- The following list of eligible expenses includes any maximums that apply under the plan. The expenses will only be paid if they are reasonable and customary for the area in which they were incurred,



they are medically necessary and recommended by a licensed doctor (other than paramedical practitioner expenses) and they are not prohibited by any government health plan:

- Professional services of a physician for:

  Non-emergency treatment outside Canada will be paid up to the reasonable and customary charges for the area in which the claimant resides.

  Quebec residents (for non-emergency treatment) will be reimbursed according to the area the expense is rendered if outside Quebec but inside Canada.

- Hospital charges for treatment resulting from an emergency while you are outside of Canada for a temporary period. Reimbursement will be limited to the difference between the hospital's charge for ward accommodation and the provincial health plan allowance, and hospital services and supplies (excluding doctors' fees and special nursing fees). Coverage is provided for a maximum of 31 days per period of disability.
- Services of a registered nurse registered or certified nursing assistant or licensed practical nurse up to a lifetime maximum payment of $5,000 per covered person. Nurses who are a resident in the covered person's home or who are related to the covered person will not be covered. All claims will require the pre-approval of the insurance company prior to payment.
- Drugs, sera and injectibles available only with a doctor's or dentist's prescription and which are dispensed by a licensed pharmacist, physician or dentist. Non-prescription drugs and supplies required as a result of a colostomy and/or treatment of cystic fibrosis, diabetes and parkinsonism will also be covered.

- Smoking cessation treatment available only with a doctor's prescription, to a lifetime maximum of one treatment per person.
- Diagnostic procedures, radiology, oxygen (including equipment necessary for administration) and blood transfusions.
- Licensed ground ambulance services to and from a local hospital and to and from the point of arrival and departure.
- Emergency transportation by any form of licensed ambulance (including air) or public transportation to and from the nearest hospital in which treatment can be given, subject to one round trip per calendar year.
- Purchase of a truss, brace, crutch, artificial limb or eye, and one pair of elastic support hose per calendar year.
- Rental or purchase (at the plan's discretion) of a wheelchair, hospital bed or respirator/ventilator.
- Room, board and normal nursing care provided by a licensed nursing home for convalescent or chronic care, but excluding custodial care, to a maximum payment of $20.00 per day.
- Dental treatment which is required as the direct result of accidental injury to natural teeth. Treatment must be rendered within 6 months of the date of the accident. Reimbursement by the plan will be limited to the cost of the least expensive dental services, which would produce a professionally adequate result.
- Purchase of orthotics to a maximum payment of $475 a pair, limited to two pairs every three calendar years. The orthotics must be custom-made and must be prescribed and dispensed by a physician, podiatrist or orthopaedic surgeon.

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- Purchase of orthopaedic shoes, which form part of a brace. If the shoes do not form part of a brace, reimbursement will be limited to two pairs per calendar year and the greater of the actual cost of the specific adjustment to the shoe or 50% of the total cost of the shoe.
- Services of a licensed, certified or registered psychologist, speech therapist, podiatrist, chiropractor, osteopath, physiotherapist, naturopath or masseur, up to $500 per calendar year, per practitioner.
- Out patient services of a hospital, excluding physicians and special nursing fees.
- Purchase of wigs and hairpieces required as the result of cancer treatment up to a maximum payment of $500 while covered under the plan.

## Vision care expenses covered by the plan

The Company retiree vision care plan will only pay for expenses recommended by a doctor or optometrist. The plan will cover:

- up to $100 every 24 consecutive months for the purchase of frames, lenses and the fitting of any type of prescription glasses or contact lenses;
- up to $200 every 24 consecutive months for the purchase of contact lenses required as the result of severe corneal astigmatism, severe corneal scarring, keratoconus or aphakia, provided vision can be improved to at least 20/40 with contact lenses only;
- services of visual training or remedial exercises;

- ocular examination or examinations performed by an ophthamologist or a licensed optometrist, including refraction, limited to one exam per calendar year for a child and one exam every 24 consecutive months for an adult, between the ages of 20 and 64. Provincial Plan coverage is from age 65.

## Coordination of benefits

In the event your spouse is also covered under an active or retiree group health care plan, the coordination of benefits provision applies. Claims for you and your spouse should first be submitted to your respective group health care plans. Any unpaid balance could then be submitted to the other spouse's plan for possible payment.

Claims for dependent children should first be submitted to the plan covering the parent with the earlier ***day and month*** of birth in the year.

Any unpaid balance could then be submitted to the other parent's plan for payment consideration.

At no time will more than 100% of the actual cost of the expense be paid from both plans.

The definition of an eligible dependent is:

- a natural child, adopted child, step child – must be unmarried and supported by the retiree. Coverage will continue until the attainment of age 21 or 25 so long as they continue to satisfy the the definition of a dependent.

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## What charges are not covered by the retiree health care plan?

Benefits will not be paid for charges resulting from:

- self inflicted injuries or illness, whether sane or insane;
- cosmetic surgery or treatment, unless approved by the plan, or unless treatment is required as the result of an accident and commenced within 90 days of the date of the accident;
- charges by a physician for travelling time, broken appointments, transportation costs, room rental charges or advice given by telephone or other means of telecommunication;
- any disability covered by Workers' Safety Insurance Board; war, insurrection, service in the armed forces of any country or participation in a riot;
- any drugs or medicines which are not approved by Health and Welfare Canada or which are experimental or limited in use whether they are approved or not; and
- experimental medical procedures or treatments not approved by the provincial medical association or other applicable medical society;
- periodic health examinations, required for use of a third party, or travel for health;
- expenses incurred outside Canada for hospital charges for ward accommodation, hospital services or supplies furnished during hospital confinement, or physicians except as specified under Eligible Expenses;
- any charges for services, treatment or supplies for which there would be no charge except for existence of coverage;
- hearing aids.

## How to claim benefits

Save all of your original receipts for medical, hospital, vision and prescription drugs.

Claim forms are available from the Human Resources Service Centre or from the Sun Life website (www.sunlife.ca). Complete the claim form and mail directly to the insurance company.

Claims must be submitted no later than the end of the calendar year following the year in which you incurred the expense. When your retiree health coverage ends, all outstanding claims must be submitted within 90 days following the date coverage ended.

## When does retiree health coverage end?

Your retiree health and vision care benefits will end on the earliest of:

(i) the date you request, in writing, that coverage should end

(ii) the date of death of a covered person

(iii) the date the coverage is terminated by the Company

(iv) the date the ASO contract 25113 terminates.

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## Extension of retiree health benefits

Retiree health coverage will be extended under the following conditions:

- If one of your covered dependents is hospitalized on the date their health coverage terminates, the health plan will continue to cover related medical expenses for the disabled person up to the earlier of:
  - (i) the 365th day following the date coverage ended for medical expenses, hospital expenses are extended for 90 days.
  - (ii) the date they are no longer totally disabled.
  - (iii) the date your dependent is no longer hospitalized.
- If your covered dependent is pregnant on the date that health coverage ends, the plan will continue to cover pregnancy-related expenses.

In the event of your death, coverage for your eligible spouse and dependent children will be extended until the end of the third month following the date of your death, provided your dependents were covered under the retiree health plan at the time of your death. Coverage for your spouse may be further extended provided they continue to qualify as a dependent and they are in receipt of a pension from the Company.

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# Retiree Dental Care Plan

If you retire from the Company before you reach age 65, your active group dental plan benefits will be extended for you and your eligible dependents until the date you turn age 65. Your eligible dependents are the same as those detailed under the retiree health care plan.

The Company retiree dental care plan pays 100% of the cost of basic dental treatment for you and your eligible dependents. It also pays 50% of the cost of major restorative treatment, and 50% of the cost of orthodontic treatment, for you and your eligible dependents.

The maximum per calendar year for basic and major restorative treatment combined is $2,000 per covered person. The lifetime maximum for orthodontia is $1,000 for each covered person.

Expenses are paid up to the Ontario Dental Association Fee Guide currently recognized by the plan on the date that the expense is incurred. Expenses will be paid only if they are necessary and recommended by a doctor, dentist or denturist practicing within the scope of their license, if the method of treatment is the least expensive and will produce a professionally adequate result, and if the procedures are performed by a dentist or denturist practicing within the scope of their license.

***Remember to promptly report all changes in your marital status or changes regarding your dependent children's status to the Human Resources Service Centre.***

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## Covered basic treatment (100% covered)

- ***Diagnostic services*** including oral exams once every 9 months, bitewing x-rays once every 18 months, a full mouth series of x-rays once every 24 months, and consultations with the attending dentist.
- ***Preventive services*** including prophylaxis (light cleaning and scaling) once every 9 months, application of a topical Fluoride Treatment once every 9 months, Preventative Recall Packages, space maintainers for missing primary teeth, and habit breaking appliances.
- ***Restorative services*** including amalgam, silicate, acrylic and composite restorations.
- ***Endodontics services*** (treatment of the diseases of the dental pulp) and root canal therapy.
- ***Periodontic services*** (treatment of the tissues and bones supporting the teeth including surgery, provisional splinting and occlusal equilibration). Periodontal scaling will be limited to eight units of four occurrences per covered person, per calendar year. Occlusal equilibration will be limited to four units of four occurrences per covered person, per calendar year.
- ***Prosthodontic services*** including repairs, relining and rebasing of an existing denture and repairs to an existing bridge.
- ***Oral surgery*** including diagnostic x-rays, laboratory procedures, general anaesthetic, conscious sedation, extractions (including impacted teeth), simple alveolectomy at the time of extraction, removal of tumors, cysts and neoplasms, plus the incision and drainage of an abscess.

## Covered major restorative treatment (50% covered)

- ***Restorative services*** including inlays and onlays where 3 or more tooth surfaces are involved (if one or two surfaces are involved, the expense is covered under basic services), and, crowns including gold and porcelain veneer restorations when other material is not suitable.
- ***Prosthodontic services*** including creation of an initial bridge or denture.
- ***Surgical services*** not specifically covered under basic services.
- ***Adjunctive general services*** including the injection of antibiotic drugs when prescribed by a dentist.
- ***Replacement of an existing bridge or denture*** provided

(i) the replacement is needed due to the extraction of a natural tooth while covered under the plan, or

(ii) the existing bridge or denture is at least 3 years old and cannot be repaired, or

(iii) the existing bridge or denture is temporary and is replaced with a permanent bridge or denture within 12 months of the date that the temporary appliance was installed.

## Covered orthodontic treatment (50% covered)

- Treatment required for the correction of malocclusion of the teeth.

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## What expenses are not covered by the retiree dental plan?

Benefits will not be paid for any charges incurred for, or in connection with:

- intentionally self-inflicted injuries or illness, whether sane or insane;
- any expenses for which coverage is provided under Workers' Safety Insurance Board or any similar legislation;
- dental treatment received from a dental or medical department maintained by any employer, association or labour union;
- examinations required by a third party;
- charges levied by physician or dentist for time spent travelling, broken appointments, transportation costs or advice given by telephone or other means of telecommunication;
- cosmetic surgery or treatment unless required as a result of an accident and treatment commenced within 90 days of the date of the accident;
- services and supplies for full mouth reconstruction, vertical dimension correction or correction of temporomandibular joint dysfunction;
- injury resulting directly or indirectly from war, insurrection, service in the armed forces of any country, or participation in a riot; and
- replacement of an appliance which has been lost, stolen or mislaid.

## What if treatment will be over $500?

A predetermination of benefits provision is an important part of a dental plan. Under this provision, if planned treatment is expected to cost more than $500, we recommend that you submit an estimate of the expenses to the insurance company ***before*** the treatment is to begin.

Your dentist will outline in a treatment plan the recommended services and the charge for each service. Supporting x-rays are usually included.

The insurance company will review the treatment plan and let you know how much of the cost you can expect will be paid by the plan.

Submit the treatment plan directly to the insurance company.

## How to claim benefits

The standard Canadian Dental Association Form is available from your dentist.

Have your dentist complete the form. You complete your portion of the form and send the completed form directly to the insurance company.

Your dentist may request payment at time of treatment. If so, your expense reimbursement will be sent directly to you by the insurance company. If the dentist accepts payment directly from the insurance company, you must ***clearly*** indicate on the claim form that payment should be assigned to the dentist.

Claims must be submitted by the end of the calendar year following the year in which they were incurred.

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## When does retiree dental coverage end?

Dental benefits will end on the earliest of:

(i) the date you turn age 65

(ii) the date you request, in writing, that coverage should end

(iii) the date your coverage is terminated by the Company

(iv) the date of death of a covered person

(v) the date your dependent is no longer eligible

(vi) the date the ASO contract 25113 terminates

## Extension of retiree dental benefits

Dental expenses incurred after the date retiree dental coverage ends will not be reimbursed by the plan, unless:

(i) an impression for a denture, bridge, crown, inlay or onlay was taken prior to the date coverage ended and the appliance is installed within 30 days of the date coverage ended, or

(ii) coverage ends due to your death prior to attaining age 65 and within 90 days a covered dependent incurs dental expenses related to a course of treatment, which started prior to the date of your death.

Appendix 2
Enbridge Gas Distribution Inc.
Continuity Schedule of the OPEB Funded Status
*(in millions) (see Note 1)*

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30-Sep-01 | 30-Sep-02 | 30-Sep-03 | 31-Dec-04 | 31-Dec-05 | 31-Dec-06 | 31-Dec-07 | 30-Dec-08 | 30-Dec-09 | 30-Dec-10 | 30-Dec-09 | 30-Dec-10 |
| **Change in Accrued Benefit Obligation** | | | | | | | | | | | | |
| Benefit obligation at beginning of year | 50.40 | 54.80 | 59.60 | 62.60 | 72.00 | 89.10 | 95.00 | 99.50 | 83.20 | 81 | 77 | 74 |
| Service cost | 1.00 | 1.10 | 1.50 | 1.00 | 1.20 | 1.60 | 1.60 | 1.50 | 1.20 | 1 | 1 | 1 |
| Interest Cost | 3.50 | 3.80 | 4.40 | 3.80 | 4.50 | 4.60 | 4.90 | 5.60 | 5.40 | 5 | 5 | 5 |
| Actuarial loss/(gain) and other adjustments | 2.00 | 2.10 | (5.70) | 9.20 | 13.90 | 2.30 | 0.80 | (20.30) | (5.80) | 4 | (6) | 4 |
| Benefits paid | (2.10) | (2.20) | (2.40) | (2.40) | (2.50) | (2.60) | (2.80) | (3.30) | (3.50) | (3) | (3) | (3) |
| Net transfer in/(out) | | | | | | | | | | (2) | | (2) |
| Adjustment due to change in measurement date | | | | | | | | 0.20 | | 1 | | 1 |
| Plan amendments | | | | (2.20) | | | | | | | | |
| Employees transferred back to the Company | | | 5.20 | | | | | | | | | |
| Benefit obligation at end of year | 54.80 | 59.60 | 62.60 | 72.00 | 89.10 | 95.00 | 99.50 | 83.20 | 80.50 | 87 | 74 | 80 |
| **Change in Plan Assets** | | | | | | | | | | | | |
| Fair value of plan assets at beginning of year | - | - | - | - | - | - | - | - | - | - | - | - |
| Employer's contributions | 2.10 | 2.20 | 2.40 | 2.40 | 2.50 | 2.60 | 2.80 | 3.30 | 3.50 | 7 | 3 | 3 |
| Benefits paid | (2.10) | (2.20) | (2.40) | (2.40) | (2.50) | (2.60) | (2.80) | (3.30) | (3.50) | (3) | (3) | (3) |
| Net transfer in | | | | | | | | | | | | |
| Fair value of plan assets at end of year | - | - | - | - | - | - | - | - | - | 4 | - | - |
| **Funded Status** | | | | | | | | | | | | |
| Benefit obligation | (54.80) | (59.60) | (62.60) | (72.00) | (89.10) | (95.00) | (99.50) | (83.20) | (80.50) | (87) | (74) | (80) |
| Fair value of plan assets | - | - | - | - | - | - | - | - | - | 4 | - | - |
| Overfunded/(Underfunded) status at end of year | (54.80) | (59.60) | (62.60) | (72.00) | (89.10) | (95.00) | (99.50) | (83.20) | (80.50) | (83) | (74) | (80) |
| Contribution after measurement date | | | | 0.60 | 0.60 | 0.70 | 0.70 | 0.80 | 0.80 | | 1 | |
| Unamortized prior service cost | | | | | | | (0.70) | (0.60) | | | | |
| Unamortized net actuarial loss/(gain) | 2.00 | 4.00 | (0.50) | 8.70 | 22.40 | 23.20 | 18.90 | (2.40) | (8.50) | (4) | (9) | (4) |
| Unamortized transitional (asset)/obligation | 47.10 | 43.70 | 42.40 | 34.90 | 31.70 | 28.50 | 24.90 | 21.80 | 18.70 | 16 | 19 | 16 |
| Net Amount Recognized on the Balance Sheet | (5.70) | (11.90) | (20.70) | (27.80) | (34.40) | (42.60) | (55.70) | (63.60) | (69.50) | (71) | (63) | (68) |

Note 1: amounts in columns A through to J are from Enbridge's consolidated external financial statements, which include amounts from St. Lawrence Gas, a wholly owned subsidiary.
The balances in columns K and L presents the 2009 and 2010 results excluding the impact of St. Lawrence Gas.

Appendix 3
Enbridge Gas Distribution Inc.
Continuity of Transitional Obligation
*(in millions)*

| | **Beginning Balance** | **Amortization** | **Ending Balance** |
|---|---|---|---|
| 1-Oct-00 | | | 50.00 |
| 30-Sep-01 | 50.00 | 2.90 | 47.10 |
| 30-Sep-02 | 47.10 | 3.40 | 43.70 |
| 30-Sep-03 | 43.70 | 1.30 | 42.40 |
| 31-Dec-04 | 42.40 | 7.50 | 34.90 |
| 31-Dec-05 | 34.90 | 3.20 | 31.70 |
| 31-Dec-06 | 31.70 | 3.20 | 28.50 |
| 31-Dec-07 | 28.50 | 3.60 | 24.90 |
| 30-Dec-08 | 24.90 | 3.10 | 21.80 |
| 30-Dec-09 | 21.80 | 3.10 | 18.70 |
| 30-Dec-10 | 18.70 | 3.10 | 15.60 |

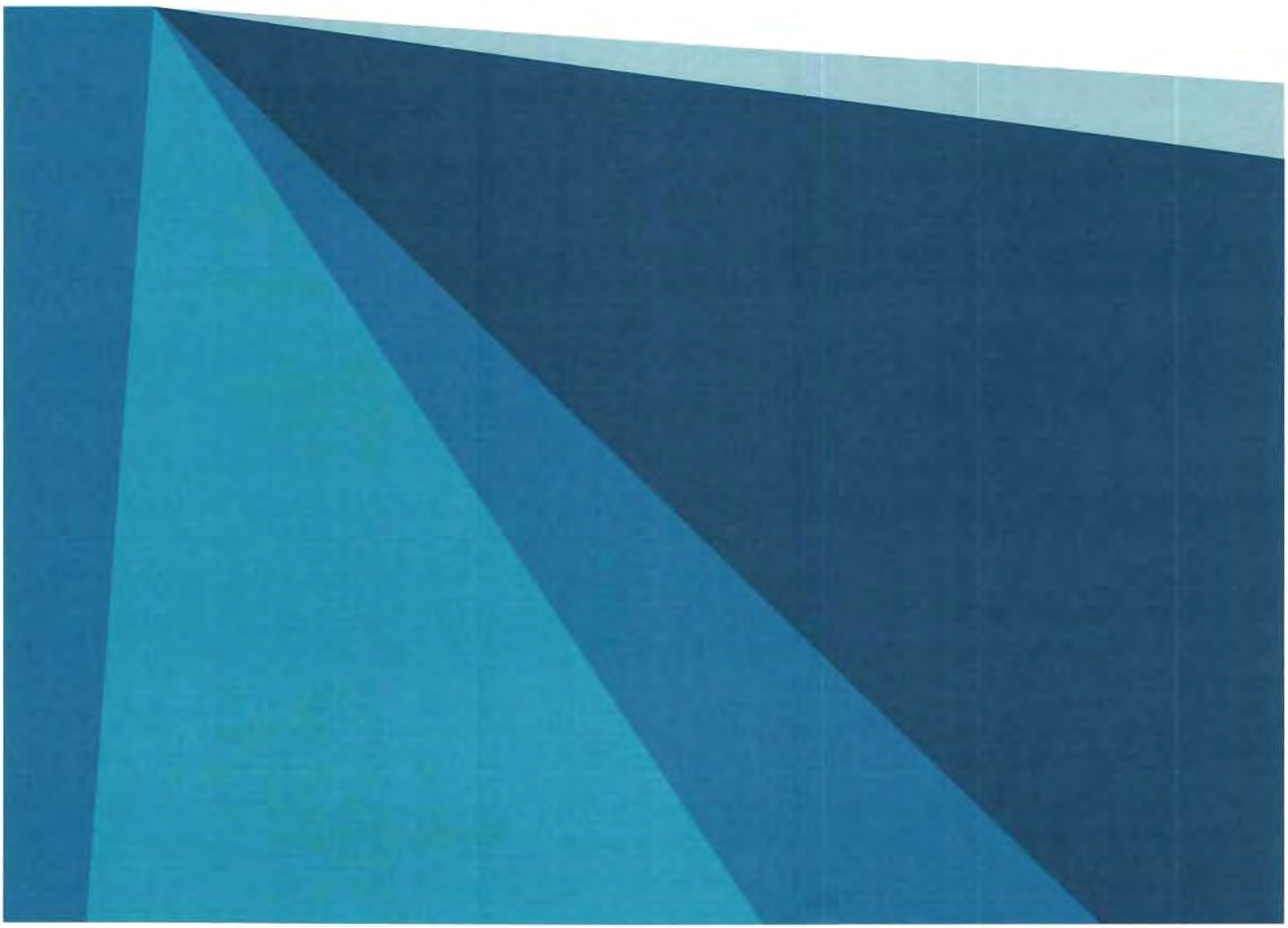
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# ESTIMATED 2013 - 2017 CASH FUNDING COSTS

## EGD NON-PENSION POST RETIREMENT PLANS

19 JANUARY 2012



MARSH & McLENNAN COMPANIES

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If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in accounting standards and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

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# 1

# Introduction

## Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the cash funding costs over 2013 to 2017 for The Non-Pension Post Retirement Plan for Employees of Enbridge Gas Distribution Inc. (the "OPEB Plan") based on economic conditions at October 31, 2011. Actual cash funding costs in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of 2013 to 2017 OPEB costs from ratepayers.

Note that information contained in this report reflects projected costs in respect of Enbridge Gas Distribution Inc. only, and not any affiliates to the Company.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

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# 2

# Background Information

## Determination of Cash Funding Costs

The EGD OPEB Plan is a defined benefit ("DB") plan. The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

## Historical Funding

Historical estimated cash costs to the EGD OPEB plan are summarized below.

Estimated Cash Costs

| | EGD OPEB Plan* |
|---|---|
| 2002 | $2.3M |
| 2003 | $2.4M |
| 2004 | $2.4M |
| 2005 | $2.5M |
| 2006 | $2.6M |
| 2007 | $2.8M |
| 2008 | $3.1M |
| 2009 | $3.3M |
| 2010 | $3.3M |
| 2011 | $3.4M |
| **Total** | **$28.1M** |

* Estimated cash costs for 2002 to 2006 include EGD affiliates

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# 3

## Financial Results

We have projected the results of the January 1, 2009 actuarial valuation of the OPEB Plan for financial reporting purposes forward to each of the years ending 2011 through 2016. The purpose of these projections is to estimate the cash funding costs for 2013 through 2017. **The projections are based on the assumptions described in Appendix C. The actual plan experience over this period may differ significantly from these assumptions.**

The expected cash funding costs for the plans over 2013 – 2017 are summarized below.

Cash Costs ($Millions)

| | EGD OPEB |
|---|---|
| 2013 Projected Cash Cost | $3.8 |
| 2014 Projected Cash Cost | $4.0 |
| 2015 Projected Cash Cost | $4.3 |
| 2016 Projected Cash Cost | $4.6 |
| 2017 Projected Cash Cost | $4.8 |

## Important to Note

The purpose of this report is to estimate the cash funding costs over 2013 - 2017. However, the actual level of costs in 2013 – 2017 is highly dependent on:

- Future health care claims costs and trends; and,
- Actual plan demographic experience.

These items will cause actual cash costs over 2013 – 2017 to differ from the estimates provided in this report.

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# 4

## Actuarial Opinion

Management has selected the assumptions used in the projections of cash funding costs. They are Management's best estimate assumptions. I am not expressing any opinion on these assumptions.

In my opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The methods employed in the projections are appropriate.

This report has been prepared, and my opinion given, in accordance with accepted actuarial practice in Canada.



Nicholas H. Gubbay
FCIA, FFA

January 19, 2012

Date

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# APPENDIX A

## Sensitivity of Results

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. As a result, the projected cash funding costs are not sensitive to "shocks" impacting the determination of the liability discount rate.

It should be noted that future health care cost trends are especially difficult to predict and actual experience is likely to differ from expected. In addition, changes to provincial drug benefit plans have the potential to shift some or most of the cost of seniors' drug claims to employer sponsored retiree benefit plans, thereby dramatically increasing the cost of seniors' drugs claimed under the grandfathered portion of the EGD OPEB Plan.

# APPENDIX B

## Required Disclosures

### Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The information presented in this report has been prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

- The projections of cash funding costs have been prepared based on methods and assumptions selected by Management;

- Our calculations are based on the assumptions and methodology described in Appendix C. The discount rate assumption has been updated from the rate used in the December 31, 2010 valuation to reflect market conditions as at October 31, 2011 and new CIA guidance released in September 2011.

- Our calculations are based on extrapolations of a valuation performed using membership data as at January 1, 2009. The membership data used in our projections and calculations is summarized in Appendix D.

- Our calculations reflect the provisions of the Plan as at October 31, 2011. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix E.

### Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent October 31, 2011 which, in our opinion, would have a material impact on the results of the projection.

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# APPENDIX C

## Actuarial Methods and Assumptions

### Actuarial Methods

#### *Funding Policy*

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

### Actuarial Assumptions

The following assumptions, provided to us by Management, were used in valuing the benefit obligations under the plan.

| | | |
|---|---|---|
| *Measurement date* | 31 December | |
| *Salary increases* | 3.50% per annum | |
| *Medical cost trend rates* | Hospital | 4.50% per annum |
| | Prescription drugs | 9.375% per annum in 2009 grading down to 4.50% per annum in and after 2029. The trend rates are reduced by 0.5% per year after age 65 for Ontario members to reflect the inclusion of the Ontario Drug Benefit costs |
| | Other medical | 4.50% per annum |
| | Vision care | 4.50% per annum, with an effective 0% per annum net trend rate due to the low fixed dollar limit that exists for the benefit |
| *Provincial health trend rate (non-grandfathered)* | | 0.00% per annum |
| *Retiree HSA trend rate* | | 0.00% per annum |
| *Dental cost trend rate* | | 4.50% per annum |
| *Mortality* | Uninsured Pensioners' (UP) Table for 1994 with generational mortality improvements | |

| | | | |
|---|---|---|---|
| *Withdrawal* | Rates at sample ages are shown below: | | |
| | Age | Male | Female |
| | 25 | 5.0% | 13.0% |
| | 35 | 4.6% | 8.5% |
| | 45 | 2.5% | 3.9% |
| | 55 | 0.0% | 0.0% |
| | No withdrawal assumed after attainment of eligibility for retirement. | | |
| *Disability incidence* | No explicit allowance has been made for disability prior to retirement. | | |
| *Retirement rates* | If 30 years of continuous service is not reached between ages 55 and 59 inclusive, then the table rates apply, otherwise 20% of the members will retire at the first age at which 30 years of continuous service and age 55 are reached. At all other ages, rates follow the table below. | | |
| | Age | Rate | |
| | 55 – 56 | 5.0% | |
| | 57 – 58 | 7.5% | |
| | 59 | 10.0% | |
| | 60 – 64 | 20.0% | |
| | 65 | 100.0% | |
| *Marital status* | For active members, 80% are assumed to be married at retirement with males assumed to be 2 years older than their female spouses.<br>For current retirees, actual marital status and spousal age is assumed. | | |
| *2009 Age 65 per capita claims costs excluding administration and taxes* | Hospital | $71 | |
| | Prescription drugs | $902 | |
| | Other medical | $134 | |
| | Vision care | $15 | |
| | Dental care | $516 | |
| | Total | $1,638 | |
| | The current per capita medical and dental costs were based on actual claims experience from 01 July 2009 to 30 June 2011 and adjusted to the midpoint of the valuation year.<br>Drug costs are shown before the impact of any provincial drug plan. | | |
| *Provincial Health Premiums* | The company pays 50% of the cost of provincial health premiums (shown below) for non-grandfathered retirees in British Columbia. We have incorporated the cost of these premiums in our valuation.<br><br>Monthly premiums Single $54 Family $96. The Company cost is frozen at the above (2004) levels. | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| *Increases in utilization by age* | Cost at Age | | | | | |
| | Attained Age | Hospital | Drug | Other Medical | Dental | Vision |
| | 55 | 45% | 75% | 106% | 106% | 106% |
| | 60 | 64% | 88% | 103% | 104% | 103% |
| | 65 | 100% | 100% | 100% | 100% | 100% |
| | 70 | 161% | 109% | 102% | 95% | 97% |
| | 75 | 253% | 113% | 110% | 90% | 95% |
| | 80 | 388% | 114% | 121% | 83% | 92% |
| *Prescription drug offset assumption at age 65 and after* | The following cost-offsets were assumed to reflect the impact of provincial drug plans:<br>Québec: 50%<br>Ontario 65%<br>Alberta: 55%<br>Prince Edward Island 35%<br>All other provinces: 0% | | | | | |
| *Administrative expenses as a percentage of paid claims* | Medical | 5.00% plus 2.28% for stop loss charge plus applicable taxes | | | | |
| | Dental | 5.00% plus applicable taxes | | | | |
| | Retiree HSA | 5.00% plus applicable taxes | | | | |
| | Life insurance | 2.50% plus applicable taxes | | | | |
| *Taxes* | Premium Tax<br>Quebec – 2.55%<br>Other – 2.00%<br>Retail Sales Tax<br>Quebec – 9.00%<br>Ontario – 8.00% | | | | | |
| *Participation* | 100% of members are assumed to participate in the retiree health plan. | | | | | |

**Our assumptions are based on the economic environment as of October 31, 2011, and input provided by the Company. Actual cash costs over 2013 to 2017 will differ from those used in these projections.**

# APPENDIX D

## Membership Data

### Analysis of Membership Data at January 1, 2009

For purposes of these estimates, we have based our projections on membership data as at January 1, 2009, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix C.

Membership data for the EGD OPEB Plan, including affiliates, as at January 1, 2009 are summarized below.

*Active Membership Data*

| | 01 January 2009 | | | |
|---|---|---|---|---|
| | Number | Average Age | Average Service | Average Salary |
| **Grandfathered Plan** | | | | |
| Non Union | 389 | 54.5 | 27.6 | $83,448 |
| Union | 360 | 54.4 | 26.4 | $58,205 |
| Part Time | 4 | 60.3 | 11.3 | $30,519 |
| **Non-Grandfathered Plan** | 1,294 | 39.9 | 7.7 | $69,578 |
| **Total** | 2,047 | 45.3 | 14.8 | $70,137 |

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## *Inactive Membership Data*

| | 01 January 2009 | | |
|---|---|---|---|
| | **Less than age 65** | **Greater than age 65** | Total |
| **Grandfathered Plan** | | | |
| Number of Retirees | 253 | 844 | 1,097 |
| Average age of Retirees | 60.8 | 74.3 | 71.2 |
| Average Life Benefit | $100,765 | $5,000 | $27,086 |
| Number of Spouses of Retirees | 278 | 577 | 855 |
| Average age of Spouses | 58.7 | 73.2 | 68.5 |
| Number of Surviving Spouses | 29 | 145 | 174 |
| Average Age of Surviving Spouses | 56.4 | 77.0 | 73.6 |
| **Non-Grandfathered Plan** | | | |
| Number of Retirees | | | 13 |
| Average age of Retirees | | | 60.2 |
| Average Life Benefit | | | $10,000 |
| Number of Spouses of Retirees | | | 11 |
| Average age of Spouses | | | 60.5 |

# APPENDIX E

## Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the EGD OPEB Plan in effect on October 31, 2011.

The following is a summary of the main provisions of the Plan in effect on October 31, 2011. This summary is not intended as a complete description of the EGD OPEB Plan.

### Grandfathered Plan Summary (Traditional Plan)

#### *Eligibility*

Employees who are eligible to retire under the terms of the pension plan (at age 55) are eligible for post-retirement benefits. Current retirees, surviving spouses, and employees with 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible to elect the traditional plan or the RHSA.

Spouses and dependants of retirees are eligible for health and dental coverage as well. Dental coverage ceases when the retiree reaches age 65.

On the retiree's death, health and dental coverage continues for the spouse and dependents. Dental coverage ceases when the surviving spouse reaches age 65, and there is no continuation of dental coverage if the surviving spouse is over age 65 when the retiree dies.

#### *Cost Sharing*

All costs for retiree benefits are employer paid.

#### *Life Insurance*

| Group | Pre Age 65 coverage | Post Age 65 coverage |
|---|---|---|
| Non Union | 2 x annual earnings at retirement | $5,000 |
| Union | $40,000 | $5,000 |
| Part-Time | $15,000 | $5,000 |

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## *Medical and Dental Benefits*

### *Hospital Benefits*

Benefits cover 100% of semi-private room and board charges in excess of charges for ward accommodation and for ward-level user fees, where applicable. Hospital charges related to chronic case services are limited to a lifetime maximum of $10,000 per covered person.

## *Major Medical Benefits*

### *Reimbursement Percentages*

- 100% for paramedical practitioners and vision care expenses.
- 90% of first $1,000 of family's eligible expenses per calendar year and 100% of remaining eligible expenses.

### *Deductible*

- None.

### *Maximum*

- $50,000 per person in any three consecutive calendar years.

### *Eligible Expenses*

- Prescription drugs.
- Ambulance services.
- Medical supplies and services (e.g. artificial limbs, orthopaedic shoes).
- Professional services.
- Services of a registered nurse, subject to a lifetime maximum of $5,000.
- Vision care ($100 per person for frames/lenses, $200 for contacts per person every 24 consecutive months).
- Hospital charges for emergency treatment outside Canada.

### *Provincial Benefits- Ontario Bill 26*

Seniors age 65 and over in Ontario with sufficiently high income are required to pay the first $100 of annual drug costs followed by a $6.11 dispensing fee per prescription. The Plan reimburses retirees for these amounts.

### *Dental Benefits*

*Reimbursement Percentages*

- 100% of basic expenses.
- 50% of major restorative expenses.
- 50% of orthodontic expenses.

*Deductible*

- None.

*Fee Guide*

Current Provincial Dental Association Fee Guide.

*Dental Maximums*

- $2,000 per person per calendar year for basic and major restorative expenses combined.
- $1,000 per person lifetime for orthodontic expenses.

## Non-Grandfathered Plan Summary (Retiree Health Spending Account – RHSA)

### *Eligibility*

Current retirees, surviving spouses, and employees that did not qualify by having 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible for the RHSA plan if the employee has at least five years of employment when they retire.

On the retiree's death, the RHSA continues for dependants. Provincial health premiums also continue to be paid (50%).

### *Cost Sharing*

With the exception of provincial health premiums, all costs for retiree benefits are employer paid.

### *Life Insurance*

Life coverage will be $10,000.

## *Health Spending Account*

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

## *British Columbia Health Premiums*

The Company will pay for British Columbia health premiums at 50% of the 2004 rates.



Mercer (Canada) Limited
550 Burrard Street
Suite 900
Vancouver, BC V6C 3S8
604 683 6761





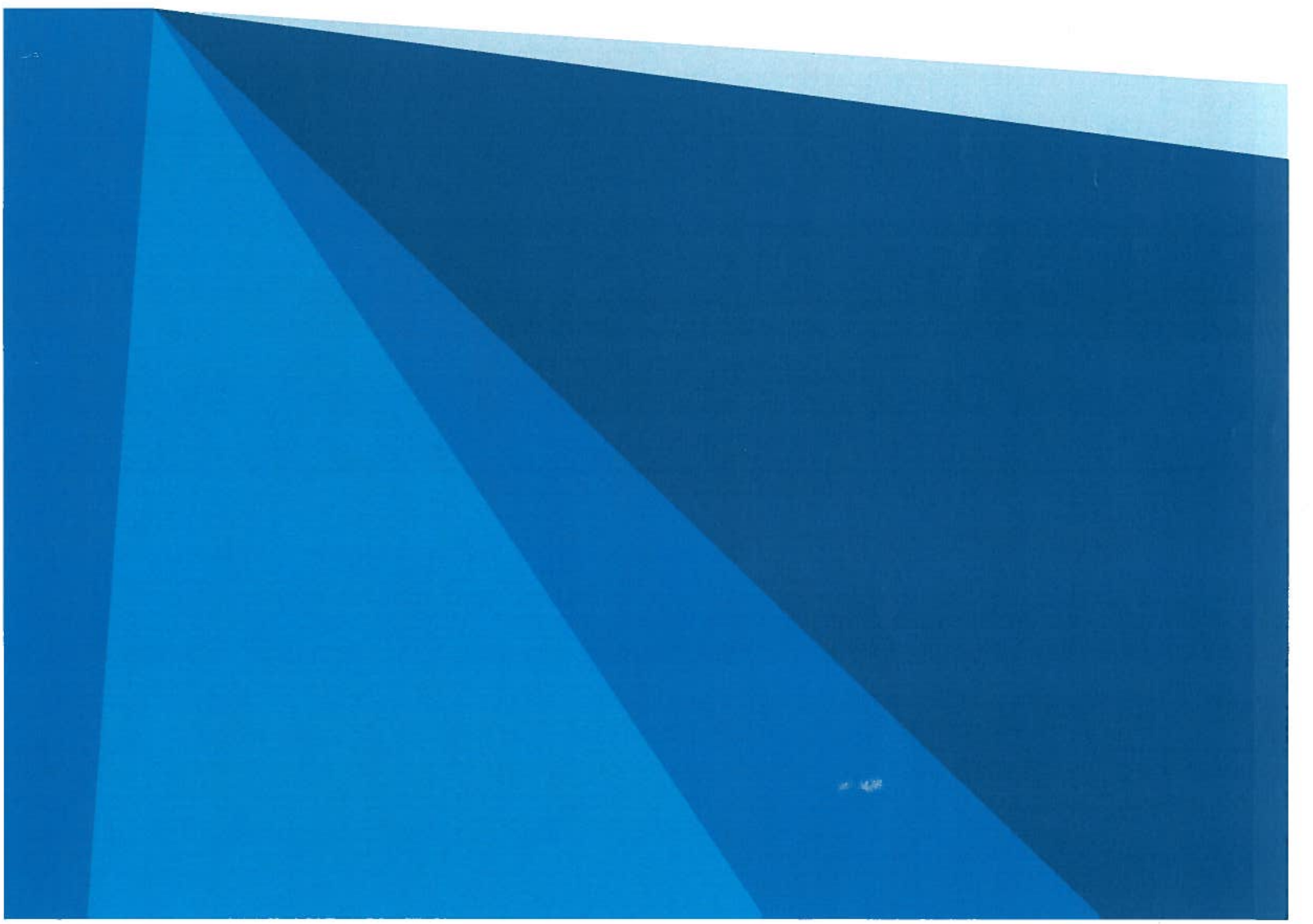
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# ESTIMATED 2013 - 2017 ACCRUAL COSTS
# EGD NON-PENSION POST RETIREMENT PLANS

19 JANUARY 2012



MARSH & McLENNAN COMPANIES

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# 1

# Introduction

## Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the accrual (i.e. accounting) costs over 2013 to 2017 for The Non-Pension Post Retirement Plan for Employees of Enbridge Gas Distribution Inc. (the "OPEB Plan") based on economic conditions at October 31, 2011. Actual accrual costs in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of 2013 to 2017 OPEB costs from ratepayers.

Note that information contained in this report reflects liabilities and costs in respect of Enbridge Gas Distribution Inc. only, and not any affiliates to the Company.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

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# Background Information

## Determination of Accrual Costs

The EGD OPEB Plan is a defined benefit ("DB") plan. Accrual costs in respect of the Plan are determined annually based on actuarial valuations and extrapolations for financial reporting purposes.

The Company has indicated that only direct charges to the Statement of Profit & Loss ("P&L charges") are applicable for determining costs on the accrual basis. Therefore, all accrual costs in the body of this report only reflect P&L charges. Charges to the Statement of Other Comprehensive Income ("OCI charges") have been included in Appendix B, for information purposes.

## Accounting Standards and Methodology

The most recent actuarial valuation of the OPEB Plan for financial reporting purposes was as at January 1, 2009. This valuation has been extrapolated forward and is the basis for the projections contained herein.

The Company's fiscal year end date is December 31, and the measurement date for plan obligations as described in this report is December 31.

The Company is currently transitioning from reporting under Canadian GAAP to US GAAP. By 2012, financial reporting is expected to be entirely on a US GAAP basis.

All results presented in this report are in Canadian dollars.

We have based our projections on accounting discount rates as at October 31, 2011 under the new methodology proposed by the Canadian Institute of Actuaries ("CIA") in September 2011, which the Company has now adopted.

Additional details on the assumptions and methodology used in these projections are given in Appendix D.

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## Current Economic Environment

The financial markets have not been favourable to OPEB plans in Canada in 2011. In particular, the health of these plans has deteriorated due to the following event:

- Accounting discount rates have dropped by approximately 0.90% from the beginning of the year to October 31, 2011.[1] A reduction in discount rates leads to an increase in liabilities.

We have based our projection of costs on economic data as of October 31, 2011.

[1] Reflecting the change in methodology adopted by Enbridge, which results in a lower discount rate than the prior discount rate methodology.

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# Financial Results

## Estimated Financial Position at December 31, 2011 and Projected Future Financial Positions

We have projected the results of the January 1, 2009 actuarial valuations of the OPEB Plan for financial reporting purposes forward to each of the years ending 2011 through 2016. The purpose of these projections is to estimate the accrual costs for 2013 through 2017. **The projections are based on the economic environment as at October 31, 2011 and assumptions described in Appendix D. The actual economic environment as at each of the years ending 2011 through 2016 and actual plan experience over this period may differ significantly from these assumptions.**

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## *Projected Accounting Balance Sheets*

The table below details the estimated balance sheet position of the OPEB Plan as at December 31, 2011, as well as the projected position of the plans at each of year-end 2012 – 2016, assuming plan experience unfolds according to the assumptions described in Appendix D.

Balance Sheet Position ($Millions)

| | EGD OPEB |
|---|---|
| **12.31.2011 (Estimated)** | |
| Assets | $0 |
| Benefit obligation | $92.0 |
| Excess (deficit) | ($92.0) |
| **12.31.2012 (Projected)** | |
| Assets | $0 |
| Benefit obligation | $93.6 |
| Excess (deficit) | ($93.6) |
| **12.31.2013 (Projected)** | |
| Assets | $0 |
| Benefit obligation | $95.4 |
| Excess (deficit) | ($95.4) |
| **12.31.2014 (Projected)** | |
| Assets | $0 |
| Benefit obligation | $96.9 |
| Excess (deficit) | ($96.9) |
| **12.31.2015 (Projected)** | |
| Assets | $0 |
| Benefit obligation | $98.1 |
| Excess (deficit) | ($98.1) |
| **12.31.2016 (Projected)** | |
| Assets | $0 |
| Benefit obligation | $99.0 |
| Excess (deficit) | ($99.0) |

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## Summary of Accrual Costs

Based on the projected financial positions above, the resulting US GAAP P&L accrual costs for the plans over 2013 – 2017 are summarized below.

Accrual Costs – US GAAP ($Millions)

| | EGD OPEB |
|---|---|
| 2013 Projected P&L Charge | $5.5 |
| 2014 Projected P&L Charge | $5.5 |
| 2015 Projected P&L Charge | $5.5 |
| 2016 Projected P&L Charge | $5.5 |
| 2017 Projected P&L Charge | $5.4 |

## Important to Note

The purpose of this report is to estimate the accrual costs over 2013 - 2017. However, the actual level of costs in 2013 – 2017 is highly dependent on:

- Changes in long-term high-quality corporate bond yields after October 31, 2011;
- Any changes to the Company's discount rate methodology in the future;
- Future health care claims costs and trends; and,
- Actual plan demographic experience.

These items will cause actual accrual costs over 2013 – 2017 to differ from the estimates provided in this report.

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## Actuarial Opinion

The methods used in the projections of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of US accounting standards (US GAAP).

Management has selected the assumptions used in the projections of plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with US accounting standards (US GAAP). I am not expressing any opinion on these assumptions.

In my opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The calculations have been made in accordance with the requirements of US accounting standards (US GAAP), reflecting application of the Company's accounting policies described in this report.

This report has been prepared, and my opinion given, in accordance with accepted actuarial practice in Canada.



Nicholas H. Gubbay
FCIA, FFA

January 19, 2012
Date

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# APPENDIX A

## Sensitivity of Results

The estimated impact on accrual costs of positive and negative "shocks" to the plan's benefit obligations are given in this appendix. These "shocks" are assumed to occur at the start of 2013 in all scenarios.

### Yield curve shift of +/- 1%

This scenario assumes a parallel shift at the start of 2013 in the yield curve which benefit obligation discount rates are based on.

**Table A.1: Positive Obligation Shock in 2013 (+1% shift in yield curve)**

| | Accrual Costs – ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $5.5 | - |
| 2014 | $5.5 | - |
| 2015 | $5.5 | - |
| 2016 | $5.6 | *$0.1* |
| 2017 | $5.6 | *$0.2* |

**Table A.2: Negative Obligation Shock in 2013 (-1% shift in yield curve)**

| | Accrual Costs – ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $6.1 | *$0.6* |
| 2014 | $6.0 | *$0.5* |
| 2015 | $5.9 | *$0.4* |
| 2016 | $5.8 | *$0.3* |
| 2017 | $5.7 | *$0.3* |

### Health Care Cost Trends

It should be noted that future health care cost trends are especially difficult to predict and actual experience is likely to differ from expected. In addition, changes to provincial drug benefit plans have the potential to shift some or most of the cost of seniors' drug claims to employer sponsored retiree benefit plans, thereby dramatically increasing the cost of seniors' drugs claimed under the grandfathered portion of the EGD OPEB Plan.

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# APPENDIX B

## Total Accrual Costs

The accrual costs shown on page 6, and in Appendix A, are only in respect of direct charges to the P&L statement. Under US GAAP, additional charges (primarily in respect of recognizing actuarial gains and losses) are reflected in the OCI statement. This appendix includes estimates of both direct P&L charges and indirect OCI charges over 2013 to 2017.

**Table B.1: Projected Financial Position**
Accrual Costs – US GAAP ($Millions)

| | P&L CHARGE | OCI CHARGE | TOTAL CHARGE |
|---|---|---|---|
| 2013 Charge | $5.5 | - | $5.5 |
| 2014 Charge | $5.5 | - | $5.5 |
| 2015 Charge | $5.5 | - | $5.5 |
| 2016 Charge | $5.5 | - | $5.5 |
| 2017 Charge | $5.4 | - | $5.4 |

### Sensitivity to yield curve shift of +/- 1%

As described in Appendix A, this scenario assumes a parallel shift at the start of 2013 in the yield curve which benefit obligation discount rates are based on.

**Table B.2: Positive Obligation Shock in 2013 (+1% shift in yield curve)**
Accrual Costs – US GAAP ($Millions)

| | P&L CHARGE | OCI CHARGE | TOTAL CHARGE |
|---|---|---|---|
| 2013 Charge | $5.5 | ($11.9) | ($6.4) |
| 2014 Charge | $5.5 | - | $5.5 |
| 2015 Charge | $5.5 | - | $5.5 |
| 2016 Charge | $5.6 | - | $5.6 |
| 2017 Charge | $5.6 | - | $5.6 |

**Table B.3: Negative Obligation Shock in 2013 (-1% shift in yield curve)**
Accrual Costs – US GAAP ($Millions)

| | P&L CHARGE | OCI CHARGE | TOTAL CHARGE |
|---|---|---|---|
| 2013 Charge | $6.1 | $14.2 | $20.3 |
| 2014 Charge | $6.0 | ($0.7) | $5.3 |
| 2015 Charge | $5.9 | ($0.6) | $5.3 |
| 2016 Charge | $5.8 | ($0.5) | $5.3 |
| 2017 Charge | $5.7 | ($0.5) | $5.2 |

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# APPENDIX C

## Required Disclosures

### Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The information presented in this report has been prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.
- The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions and accounting policies selected by Management;
- We have projected benefit obligations forward using the expected cost of benefits accruing over 2011 - 2016, reflecting interest over each period and adjusting year-end 2011 benefit obligations to reflect the economic environment as at October 31, 2011. Benefit obligations in future periods are projected forward with these same October 31, 2011 assumptions and methodology. Projected future cash flows have also been incorporated.
- Our calculations are based on the assumptions and methodology described in Appendix D. The discount rate assumption has been updated from the rate used in the December 31, 2010 valuation to reflect market conditions as at October 31, 2011 and new CIA guidance released in September 2011.
- Our calculations are based on extrapolations of a valuations performed using membership data as at January 1, 2009. The membership data used in our projections and calculations is summarized in Appendix E.
- Our calculations reflect the provisions of the Plan as at October 31, 2011. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix F.

### Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent October 31, 2011 which, in our opinion, would have a material impact on the results of the projection.

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# APPENDIX D

## Accounting Methods and Assumptions

### Accounting Methods

#### *Funding Policy*

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

#### *Valuation of Benefit Obligations and Current Service Cost*

For purposes of these estimates, we have continued to use the projected unit credit method for the valuation of benefit obligations and current service cost of the plan. The objective under this method is to expense each participant's benefits under the plan as they would accrue; taking into consideration projection of benefit costs to and during retirement. Thus, the total benefit, to which each participant is expected to become entitled at retirement, is broken down into units, each associated with a year of past or future service.

The benefit deemed to accrue for an individual during a fiscal year is the excess of the accrued benefit for valuation purposes at the end of the fiscal year over the accrued benefit for valuation purposes at the beginning of the fiscal year. Both accrued benefits are calculated from the same projections to the various anticipated separation dates. An individual's benefit obligation is the present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the service cost is the present value of the benefit deemed to accrue in the fiscal year.

The plan's service cost is the sum of the individual service costs, and the plan's benefit obligation is the sum of the individual benefit obligations for all participants under the plan.

### Accounting Policies

#### *Accounting Standards Transition*

The Company was previously reporting in accordance with Canadian GAAP accounting standards.

The Company will be adopting US GAAP accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of US GAAP financial statements, the Company will transition to US GAAP from current Canadian GAAP on January 1, 2011. On that date, a transition adjustment will be made to retained earnings to bring the existing current Canadian GAAP balances in line with the requirements of US GAAP. The Company will continue to report under current Canadian GAAP for the fiscal year ending December 31, 2011.

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Two sets of financial results will be maintained for the fiscal year ending December 31, 2011, one for current Canadian GAAP and another for US GAAP. At January 1, 2012, the Company will no longer report under current Canadian GAAP and will commence with reporting entirely under US GAAP for the fiscal year ending December 31, 2012.

### *Measurement Date*

The Company's fiscal year end date is December 31, and the measurement date for plan obligations under US GAAP is also December 31.

### *Attribution*

Under US GAAP, obligations are attributed to the period beginning on the employee's date of joining the plan and ending on the date of "full eligibility" date, determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement.

### *Amortizations of Prior Service Costs and Gains and Losses*

The Company has elected to amortize past service costs resulting from plan amendments to the EGD OPEB Plan on a linear basis over the average remaining service period of active members expected to receive benefits under the plan at the time the amendments were made.

Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation are amortized over the average remaining service period of active members expected to receive benefits under the plan (12.7 years).

## Accounting Assumptions

The following assumptions, provided to us by Management, were used in valuing the benefit obligations under the plan.

| | | |
|---|---|---|
| *Measurement date* | 31 December | |
| *Discount rate* | 4.80% | |
| *Salary increases* | 3.50% per annum | |
| *Medical cost trend rates* | Hospital | 4.50% per annum |
| | Prescription drugs | 9.375% per annum in 2009 grading down to 4.50% per annum in and after 2029. The trend rates are reduced by 0.5% per year after age 65 for Ontario members to reflect the inclusion of the Ontario Drug Benefit costs |
| | Other medical | 4.50% per annum |

| | | |
|---|---|---|
| | Vision care | 4.50% per annum, with an effective 0% per annum net trend rate due to the low fixed dollar limit that exists for the benefit |
| *Provincial health trend rate (non-grandfathered)* | | 0.00% per annum |
| *Retiree HSA trend rate* | | 0.00% per annum |
| *Dental cost trend rate* | | 4.50% per annum |
| *Mortality* | Uninsured Pensioners' (UP) Table for 1994 with generational mortality improvements | |
| *Withdrawal* | Rates at sample ages are shown below: | |

| Age | Male | Female |
|---|---|---|
| 25 | 5.0% | 13.0% |
| 35 | 4.6% | 8.5% |
| 45 | 2.5% | 3.9% |
| 55 | 0.0% | 0.0% |

No withdrawal assumed after attainment of eligibility for retirement.

| | |
|---|---|
| *Disability incidence* | No explicit allowance has been made for disability prior to retirement. |
| *Retirement rates* | If 30 years of continuous service is not reached between ages 55 and 59 inclusive, then the table rates apply, otherwise 20% of the members will retire at the first age at which 30 years of continuous service and age 55 are reached. At all other ages, rates follow the table below. |

| Age | Rate |
|---|---|
| 55 – 56 | 5.0% |
| 57 – 58 | 7.5% |
| 59 | 10.0% |
| 60 – 64 | 20.0% |
| 65 | 100.0% |

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| | |
|---|---|
| *Marital status* | For active members, 80% are assumed to be married at retirement with males assumed to be 2 years older than their female spouses.<br>For current retirees, actual marital status and spousal age is assumed. |

| *2009 Age 65 per capita claims costs excluding administration and taxes* | | |
|---|---|---|
| | Hospital | $71 |
| | Prescription drugs | $902 |
| | Other medical | $134 |
| | Vision care | $15 |
| | Dental care | $516 |
| | Total | $1,638 |

The current per capita medical and dental costs were based on actual claims experience from 01 July 2009 to 30 June 2011 and adjusted to the midpoint of the valuation year.
Drug costs are shown before the impact of any provincial drug plan.

| | |
|---|---|
| *Provincial Health Premiums* | The company pays 50% of the cost of provincial health premiums (shown below) for non-grandfathered retirees in British Columbia. We have incorporated the cost of these premiums in our valuation.<br><br>Monthly premiums Single $54 Family $96. The Company cost is frozen at the above (2004) levels. |

*Increases in utilization by age*

| | Cost at Age | | | | |
|---|---|---|---|---|---|
| Attained Age | Hospital | Drug | Other Medical | Dental | Vision |
| 55 | 45% | 75% | 106% | 106% | 106% |
| 60 | 64% | 88% | 103% | 104% | 103% |
| 65 | 100% | 100% | 100% | 100% | 100% |
| 70 | 161% | 109% | 102% | 95% | 97% |
| 75 | 253% | 113% | 110% | 90% | 95% |
| 80 | 388% | 114% | 121% | 83% | 92% |

*Prescription drug offset assumption at age 65 and after*

The following cost-offsets were assumed to reflect the impact of provincial drug plans:

| | |
|---|---|
| Québec: | 50% |
| Ontario | 65% |
| Alberta: | 55% |
| Prince Edward Island | 35% |
| All other provinces: | 0% |

| *Administrative expenses as a percentage of paid* | | |
|---|---|---|
| | Medical | 5.00% plus 2.28% for stop loss charge plus applicable taxes |
| | Dental | 5.00% plus applicable taxes |

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| | | |
|---|---|---|
| *claims* | Retiree HSA | 5.00% plus applicable taxes |
| | Life insurance | 2.50% plus applicable taxes |
| *Taxes* | Premium Tax<br>Quebec – 2.55%<br>Other – 2.00%<br>Retail Sales Tax<br>Quebec – 9.00%<br>Ontario – 8.00% | |
| *Participation* | 100% of members are assumed to participate in the retiree health plan. | |

**Our assumptions are based on the economic environment as of October 31, 2011, guidance released in September 2011 by the CIA for setting the discount rate, and input provided by the Company for the December 31, 2011 accounting valuation. Actual assumptions as at year-end 2011 – 2016 will reflect the economic environment and input from the Company at those times, and may differ from those used in these projections.**

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# APPENDIX E

## Membership Data

### Analysis of Membership Data at January 1, 2009

For purposes of these estimates, we have based our projections on membership data as at January 1, 2009, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix D.

Membership data for the EGD OPEB Plan, including affiliates, as at January 1, 2009 are summarized below.

### *Active Membership Data*

| | 01 January 2009 | | | |
|---|---|---|---|---|
| | **Number** | **Average Age** | **Average Service** | **Average Salary** |
| **Grandfathered Plan** | | | | |
| Non Union | 389 | 54.5 | 27.6 | $83,448 |
| Union | 360 | 54.4 | 26.4 | $58,205 |
| Part Time | 4 | 60.3 | 11.3 | $30,519 |
| **Non-Grandfathered Plan** | 1,294 | 39.9 | 7.7 | $69,578 |
| **Total** | 2,047 | 45.3 | 14.8 | $70,137 |

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## *Inactive Membership Data*

| | 01 January 2009 | | |
|---|---|---|---|
| | **Less than age 65** | **Greater than age 65** | **Total** |
| **Grandfathered Plan** | | | |
| Number of Retirees | 253 | 844 | 1,097 |
| Average age of Retirees | 60.8 | 74.3 | 71.2 |
| Average Life Benefit | $100,765 | $5,000 | $27,086 |
| Number of Spouses of Retirees | 278 | 577 | 855 |
| Average age of Spouses | 58.7 | 73.2 | 68.5 |
| Number of Surviving Spouses | 29 | 145 | 174 |
| Average Age of Surviving Spouses | 56.4 | 77.0 | 73.6 |
| **Non-Grandfathered Plan** | | | |
| Number of Retirees | | | 13 |
| Average age of Retirees | | | 60.2 |
| Average Life Benefit | | | $10,000 |
| Number of Spouses of Retirees | | | 11 |
| Average age of Spouses | | | 60.5 |

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# APPENDIX F

## Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the EGD OPEB Plan in effect on October 31, 2011.

The following is a summary of the main provisions of the Plan in effect on October 31, 2011. This summary is not intended as a complete description of the EGD OPEB Plan.

### Grandfathered Plan Summary (Traditional Plan)

#### *Eligibility*

Employees who are eligible to retire under the terms of the pension plan (at age 55) are eligible for post-retirement benefits. Current retirees, surviving spouses, and employees with 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible to elect the traditional plan or the RHSA.

Spouses and dependants of retirees are eligible for health and dental coverage as well. Dental coverage ceases when the retiree reaches age 65.

On the retiree's death, health and dental coverage continues for the spouse and dependents. Dental coverage ceases when the surviving spouse reaches age 65, and there is no continuation of dental coverage if the surviving spouse is over age 65 when the retiree dies.

#### *Cost Sharing*

All costs for retiree benefits are employer paid.

#### *Life Insurance*

| Group | Pre Age 65 coverage | Post Age 65 coverage |
|---|---|---|
| Non Union | 2 x annual earnings at retirement | $5,000 |
| Union | $40,000 | $5,000 |
| Part-Time | $15,000 | $5,000 |

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## *Medical and Dental Benefits*

### *Hospital Benefits*

Benefits cover 100% of semi-private room and board charges in excess of charges for ward accommodation and for ward-level user fees, where applicable. Hospital charges related to chronic case services are limited to a lifetime maximum of $10,000 per covered person.

### *Major Medical Benefits*

### *Reimbursement Percentages*

- 100% for paramedical practitioners and vision care expenses.
- 90% of first $1,000 of family's eligible expenses per calendar year and 100% of remaining eligible expenses.

### *Deductible*

- None.

### *Maximum*

- $50,000 per person in any three consecutive calendar years.

### *Eligible Expenses*

- Prescription drugs.
- Ambulance services.
- Medical supplies and services (e.g. artificial limbs, orthopaedic shoes).
- Professional services.
- Services of a registered nurse, subject to a lifetime maximum of $5,000.
- Vision care ($100 per person for frames/lenses, $200 for contacts per person every 24 consecutive months).
- Hospital charges for emergency treatment outside Canada.

### *Provincial Benefits- Ontario Bill 26*

Seniors age 65 and over in Ontario with sufficiently high income are required to pay the first $100 of annual drug costs followed by a $6.11 dispensing fee per prescription. The Plan reimburses retirees for these amounts.

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### *Dental Benefits*

### *Reimbursement Percentages*

- 100% of basic expenses.
- 50% of major restorative expenses.
- 50% of orthodontic expenses.

### *Deductible*

- None.

### *Fee Guide*

Current Provincial Dental Association Fee Guide.

### *Dental Maximums*

- $2,000 per person per calendar year for basic and major restorative expenses combined.
- $1,000 per person lifetime for orthodontic expenses.

## Non-Grandfathered Plan Summary (Retiree Health Spending Account – RHSA)

### *Eligibility*

Current retirees, surviving spouses, and employees that did not qualify by having 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible for the RHSA plan if the employee has at least five years of employment when they retire.

On the retiree's death, the RHSA continues for dependants. Provincial health premiums also continue to be paid (50%).

### *Cost Sharing*

With the exception of provincial health premiums, all costs for retiree benefits are employer paid.

### *Life Insurance*

Life coverage will be $10,000.

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## *Health Spending Account*

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

## *British Columbia Health Premiums*

The Company will pay for British Columbia health premiums at 50% of the 2004 rates.



Mercer (Canada) Limited
550 Burrard Street
Suite 900
Vancouver, BC V6C 3S8
604 683 6761





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# CHANGE IN ACCOUNTING METHODOLOGY – PENSION EXPENSE

## Purpose

1. Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") requests the Board for approval to recover pension expense on an accrual basis as determined by its actuaries, Mercer (Canada) Ltd. ("Mercer"), in accordance with US GAAP commencing January 1, 2013 in a manner appropriate for a rate regulated entity.

2. Enbridge proposes to switch from the cash basis of pension expense for rate regulated accounting to the accrual basis of expense. This would align the reporting for financial reporting purposes and rate making purposes which would provide more transparency and consistency for the users of the financial statement.

## Background

3. Under the current incentive regulation term ("IR"), the regulated utility operations of the Company would recover pension expense based on amounts paid/contributions made to the pension plans as this is what affects earnings (i.e., cash basis of expense). To date Enbridge has not had to make such contributions and as such has not had to recover any amounts for rate-making purposes, pending a Board decision with respect to the 2012 pension Z-factor request.

4. The Company is proposing to switch from the cash basis of pension expense to the accrual basis of pension expense and as such would like to recover pension expense for rate-making purposes on the accrual basis.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

Benefits

5. Accounting bodies have generally tried to match expenses to the proper time period in which the costs are incurred and revenues that are generated from those expenses. In the case of pension expense, the expense should be recognized in the period in which employees render services to qualify for employee future benefits. According to the CICA handbook:

> The objective of accounting for the cost of Employee Future Benefits is to recognize a liability and a cost in the reporting period in which an employee has provided the service that gives rise to the benefits. [1]

Current treatment of recovering pension expense on a cash basis does not factor in the period in which employee services were rendered, but rather the cash outlay in a year from employer contributions that has accumulated from years of employee services rendered. Further current treatment of recovering pension expense on a cash basis is unfair to current ratepayers as they bear the burden of an accumulation of years of employee services rather than current year employee services.

6. Ultimately at the time the pension plan is wound up, pension expense under the cash basis and accrual basis would be the same. However the pattern in which these expenses are incurred differ under both scenarios as the cash basis expense only arises when Enbridge is required to make contributions to the plan as stipulated by legislative requirements set by the Financial Services Commission of Ontario and calculated in accordance with actuarial standards/rules. Accrual basis of expense on the other hand arises annually as employee services are rendered.

[1] *CICA Handbook Section 3461, paragraph .002*

Therefore the accrual basis of expense is fair to ratepayers and also provides for less volatility in rates.

7. The Company has considered the impact to the ratepayer over the next five years if it were to switch from cash basis of pension expense to the accrual basis of pension expense.

Ratepayer Impact

8. In the baseline scenario results, as prepared by Enbridge's actuary Mercer, (refer to Mercer Summary), the total expense from 2013 to 2017 under the accrual basis is $106.6M versus $145.2M under the cash basis expense resulting in $38.6M less to be collected from the ratepayers over the next IR term[2].

9. In addition to an accrual basis of expense resulting in less to be collected from the ratepayer EGD is also of the view that an accrual basis of expense will result in less volatility to the ratepayer in both economy upturns and downturns resulting in greater rate stability. Appendix A shows the expense sensitivity of positive and negative asset and liability shocks to both the accrual basis and cash basis.

- The cost variance to the ratepayer under the 20% positive asset shock and 20% negative asset shock is less under the accrual basis than the cash basis by $41.0M and $15.8M respectively; and
- The cost variance to the ratepayer under the 1% positive liability shock and 1% negative liability shock is less under the accrual basis than the cash basis by $80.8M and $62.8M respectively.

[2] Based on plan experience to the end of August 31, 2011

Earnings Stability

10. Switching from a cash basis of expense to an accrual basis of expense will not impact earnings stability as long as Enbridge's rate recovery mechanism mirrors the basis for accounting for pension expense that affects earnings.

USGAAP versus CGAAP

11. The Company has used CGAAP as the basis of accounting when determining pension expense however by January 1, 2013 Enbridge will be under USGAAP.

12. Enbridge has considered the difference between the two accounting standards as it relates to the accrual method of pension expense, namely US GAAP and CGAAP, and the only significant differences are the treatment of unamortized transitional assets which under USGAAP are not permitted to be amortized, and the treatment of net actuarial gains/losses and prior service costs, which are a part of accumulated other comprehensive income under US GAAP versus pension liability under CGAAP. However, under both USGAAP and CGAAP the net actuarial gains/losses and prior service costs are amortized to pension expense. With the adoption of USGAAP the unamortized transitional assets will be written off to retained earnings (2 years worth of amortization as the balance under CGAAP would have been fully amortized by the end of 2013), and the unamortized actuarial gains/losses and prior service costs will be reclassified to accumulated other comprehensive income and amortized into pension expense over the expected average remaining service life. Therefore as a result of Enbridge adopting US GAAP ratepayers are not materially impacted.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

MERCER SUMMARY

The figures in the chart below are based on the "Estimated 2013-2017 Cash Funding Costs" and "Estimated 2013-2017 Accrual Costs" reports ("the Mercer reports") prepared by Enbridge's actuary, Mercer. Please refer to the Mercer reports filed as the appendices to this exhibit for details.

*Baseline*

Results calculated by Mercer assuming economic and demographic experience unfold exactly as expected.

Baseline Results (2013 to 2017 cumulative):

| | Cash Funding Costs | US GAAP Accrual P&L Charge |
|---|---|---|
| Cumulative Total | $145.2M | $106.6M |

*Shock to Equity Market*

Results assume that equity markets return 20% more or less than baseline assumptions.

Positive Asset Shock in 2013 (+20% Equity Return):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $65.6M | ($79.4)M | $68.0M | ($38.4)M |

Negative Asset Shock in 2013 (-20% Equity Return):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $203.6M | $58.6M | $149.4M | $42.8M |

*Yield Curve Shift*

Results assume a year-end 2013 parallel shift in the yield curve which liability discount rates are based on. It is assumed this change would not impact the fixed income portion of the plan's assets.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

Positive Liability Shock in 2013 (+1% Shift in Yield Curve):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $38.2M | ($106.9)M | $80.4M | ($26.1)M |

Negative Liability Shock in 2013 (-1% Shift in Yield Curve):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $226.3M | $81.1M | $124.9M | $18.3M |

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

UPDATED EVIDENCE

13. Enbridge received an update from Mercer ("updated Mercer report)" using plan experience to the end of March 31, 2012 as compared to the originally filed evidence which used plan experience to the end of August 31, 2011. The updated report has higher pension expense costs under both the accrual and cash basis of pension expense as the update reflects the economic environment as at March 31, 2012 as well as updated actuarial data. Specifically the increase in pension expense was due to:

    - October estimates were based on extrapolations of the December 31, 2010 actuarial valuation. The update reflects the actuarial valuation completed as of December 31, 2011. Using this valuation means plan membership data as well as the most up-to-date payroll data was updated.
    - Solvency funding discount rates and accounting discount rates have dropped by approximately 0.50% and 0.70% respectively. This reduction in discount rates results in an increase in liabilities.

    These increases were partially offset by financial markets performing slightly better then expected between August 31, 2011, and March 31, 2012.

14. Using the updated Mercer report, pension expense costs from 2013 to 2017 under the accrual basis are $143.1M versus $161.9M under the cash basis of expense.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

15. Enbridge's position to switch from the cash basis of pension expense to the accrual basis of pension expense still holds as the benefits, impact to ratepayers, and earnings stability as discussed in the original filing are still valid. Appendix – A Updated shows the expense sensitivity of positive and negative asset and liability shocks to both the accrual basis and cash basis using the updated figures per Mercer.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

MERCER SUMMARY - UPDATED

The figures in the chart below are based on the "Updated Estimated 2013-2017 Cash Funding Costs – EGD Pension Plans" and "Updated Estimated 2013-2017 Accrual Costs – EGD Pension Plans" reports (the "updated Mercer reports") prepared by Enbridge's actuary, Mercer (Canada) Limited ("Mercer"). Please refer to the updated Mercer reports filed as the appendices to this exhibit for details.

*Baseline*

Results calculated by Mercer assuming economic and demographic experience unfold exactly as expected.

Baseline Results (2013 to 2017 cumulative):

| | Cash Funding Costs | US GAAP Accrual P&L Charge |
|---|---|---|
| Cumulative Total | $161.9M | $143.1M |

*Shock to Equity Market*

Results assume that equity markets return 20% more or less than baseline assumptions.

Positive Asset Shock in 2013 (+20% Equity Return):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $86.9M | ($75.0)M | $99.1M | ($44.0)M |

Negative Asset Shock in 2013 (-20% Equity Return):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $223.9M | $62.0M | $190.2M | $47.1M |

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

*Yield Curve Shift*

Results assume a year-end 2013 parallel shift in the yield curve which liability discount rates are based on. It is assumed this change would not impact the fixed income portion of the plan's assets.

Positive Liability Shock in 2013 (+1% Shift in Yield Curve):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $58.9M | ($103.0)M | $114.0M | ($29.1)M |

Negative Liability Shock in 2013 (-1% Shift in Yield Curve):

| | Cash Funding Costs | | US GAAP Accrual P&L Charge | |
|---|---|---|---|---|
| | Total Cash Cost | Change from Baseline | US GAAP P&L Charge | Change from Baseline |
| Cumulative Total | $246.1M | $84.2M | $165.0M | $21.9M |

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

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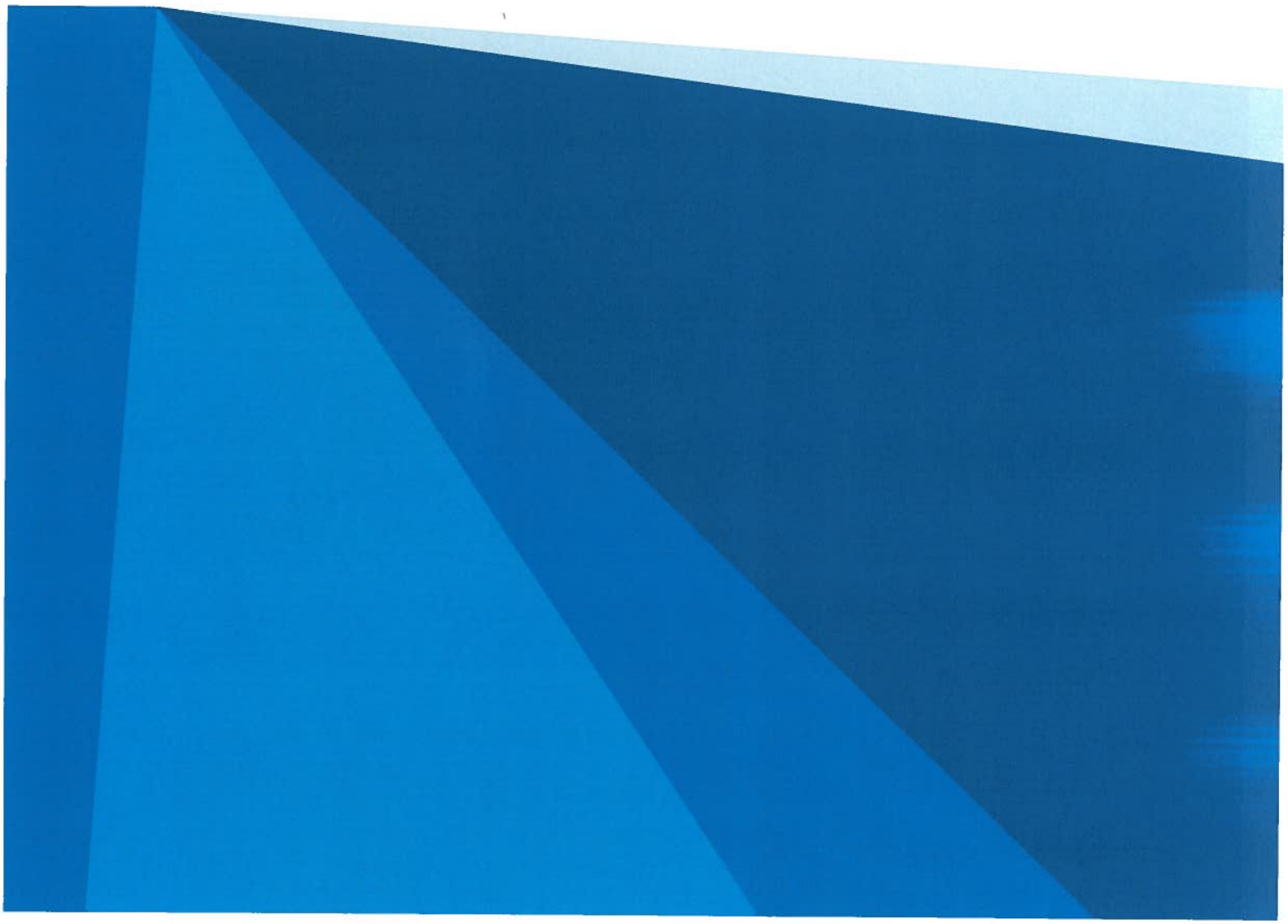
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# UPDATED ESTIMATED 2013 - 2017 ACCRUAL COSTS

## EGD PENSION PLANS

01 JUNE 2012



MARSH & McLENNAN COMPANIES

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**Note to reader regarding actuarial valuations and projections:**

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A projection is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in accounting standards and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

Because actual plan experience will differ from the assumptions used in this projection, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a projection or a valuation report.

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# 1

# Introduction

## Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the accrual (i.e. pension accounting) costs over 2013 to 2017 for:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SSERP"),

based on economic conditions at March 31, 2012. Actual accrual costs in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of 2013 to 2017 pension costs from ratepayers.

Note that information contained in this report reflects all assets, liabilities and costs in respect of all employers participating in the EGD RPP, except where specifically noted.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

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# 2

# Background Information

## Determination of Accrual Costs

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Accrual costs in respect of the EGD RPP are determined annually based on actuarial valuations and extrapolations for financial reporting purposes. The SERP and SSERP are closed supplemental pension arrangements sponsored by Enbridge Gas Distribution Inc. and are relatively small compared to the EGD RPP. Projected costs for the SERP and SSERP have been included here for completeness.

The Company has indicated that only direct charges to the Statement of Profit & Loss ("P&L charges") are applicable for determining costs on the accrual basis. Therefore, all accrual costs in the body of this report only reflect P&L charges. Charges to the Statement of Other Comprehensive Income ("OCI charges") have been included in Appendix B, for information purposes.

## Accounting Standards and Methodology

The most recent actuarial valuation of the plans for financial reporting purposes was as at December 31, 2011. These valuations have been extrapolated forward and are the basis for the projections contained herein.

The Company's fiscal year end date is December 31, and the measurement date for plan assets and obligations as described in this report is December 31.

The Company is currently transitioning from reporting under Canadian GAAP to US GAAP. By year-end 2012, financial reporting is expected to be entirely on a US GAAP basis. Results contained in this report are in accordance with US GAAP.

All results presented in this report are in Canadian dollars.

For year-end 2011 financial reporting, the Company adopted the discount rate methodology proposed by the Canadian Institute of Actuaries ("CIA") in September 2011. As of December 31, 2011 the CIA methodology resulted in a discount rate approximately 80 basis points lower than the rate determined using Enbridge's previous methodology. We have based our projections on accounting discount rates determined using the CIA methodology going forward.

Additional details on the assumptions and methodology used in these projections are given in Appendix E.

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# Financial Results

## Financial Position at December 31, 2011 and Projected Future Financial Positions

We have projected the results of the December 31, 2011 actuarial valuations of the plans for financial reporting purposes forward to each of the years ending 2012 through 2016. The purpose of these projections is to estimate the accrual costs for 2013 through 2017. **The projections are based on the economic environment as at March 31, 2012 and assumptions described in Appendix E. The actual economic environment as at each of the years ending 2012 through 2016 and actual plan experience over this period may differ significantly from these assumptions.**

For simplicity, we have excluded assets and benefit obligations with respect to the DC provision of the EGD RPP in the balance sheets shown below. However, the DC accrual costs of the EGD RPP are included in the P&L charges shown on pages 5 and 6.

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## *Projected Accounting Balance Sheets*

The table below details the actual balance sheet position of the plans as at December 31, 2011, as well as the projected position of the plans at each of year-end 2012 through 2016, assuming plan experience unfolds according to the assumptions described in Appendix E.

Balance Sheet Position ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| **12.31.2011 (Actual)** | | | | |
| Assets | $715.6 | $15.5 | $7.7 | $738.8 |
| Benefit obligation | $827.1 | $15.1 | $5.8 | $848.0 |
| Excess (deficit) | ($111.5) | $0.4 | $1.9 | ($109.2) |
| **12.31.2012 (Projected)** | | | | |
| Assets | $758.6 | $15.8 | $7.5 | $781.9 |
| Benefit obligation | $873.9 | $15.0 | $5.6 | $894.5 |
| Excess (deficit) | ($115.3) | $0.8 | $1.9 | ($112.6) |
| **12.31.2013 (Projected)** | | | | |
| Assets | $811.8 | $15.7 | $7.2 | $834.7 |
| Benefit obligation | $901.3 | $14.7 | $5.3 | $921.3 |
| Excess (deficit) | ($89.5) | $1.0 | $1.9 | ($86.6) |
| **12.31.2014 (Projected)** | | | | |
| Assets | $863.1 | $15.4 | $6.9 | $885.4 |
| Benefit obligation | $929.3 | $14.3 | $4.9 | $948.5 |
| Excess (deficit) | ($66.2) | $1.1 | $2.0 | ($63.1) |
| **12.31.2015 (Projected)** | | | | |
| Assets | $913.0 | $15.0 | $6.5 | $934.5 |
| Benefit obligation | $957.9 | $13.8 | $4.5 | $976.2 |
| Excess (deficit) | ($44.9) | $1.2 | $2.0 | ($41.7) |
| **12.31.2016 (Projected)** | | | | |
| Assets | $962.0 | $14.5 | $6.1 | $982.6 |
| Benefit obligation | $987.2 | $13.3 | $4.1 | $1,004.6 |
| Excess (deficit) | ($25.2) | $1.2 | $2.0 | ($22.0) |

## Summary of Accrual Costs

Based on the projected financial positions above, the resulting US GAAP P&L accrual costs for the plans over 2013 – 2017 are summarized below.

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Accrual Costs – US GAAP ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| 2013 Projected P&L Charge | $37.5 | $0.9 | $0.1 | $38.5 |
| 2014 Projected P&L Charge | $32.4 | $0.7 | $0.1 | $33.2 |
| 2015 Projected P&L Charge | $28.9 | $0.5 | $0.0 | $29.4 |
| 2016 Projected P&L Charge | $25.7 | $0.4 | $0.0 | $26.1 |
| 2017 Projected P&L Charge | $22.9 | $0.3 | $0.0 | $23.2 |

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## *Enbridge Gas Distribution Inc.'s Share of Funding*

In addition to Enbridge Gas Distribution Inc., two other smaller employers participate in the EGD RPP. The following tables provide the same results as those on page 5, but are only in respect of Enbridge Gas Distribution Inc.'s share of costs[1].

Accrual Costs – US GAAP ($Millions) – EGDI Only

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| 2013 Projected P&L Charge | $35.6 | $0.9 | $0.1 | $36.6 |
| 2014 Projected P&L Charge | $30.7 | $0.7 | $0.1 | $31.5 |
| 2015 Projected P&L Charge | $27.4 | $0.5 | $0.0 | $27.9 |
| 2016 Projected P&L Charge | $24.4 | $0.4 | $0.0 | $24.8 |
| 2017 Projected P&L Charge | $21.8 | $0.3 | $0.0 | $22.1 |

[1] Note that Enbridge Gas Distribution Inc. is the only employer participating in the SERP and SSERP.

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## Important to Note

The purpose of this report is to estimate the accrual costs over 2013 through 2017. However, the actual level of costs in 2013 through 2017 is highly dependent on:

- Financial market returns after March 31, 2012;
- Changes in long-term high-quality corporate bond yields after March 31, 2012;
- Any changes to the Company's discount rate methodology in the future; and,
- Actual plan demographic experience.

These items will cause actual accrual costs over 2013 through 2017 to differ from the estimates provided in this report.

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## Actuarial Opinion

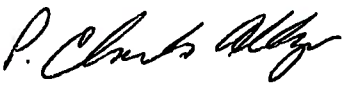
The methods used in the projections of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of US accounting standards (US GAAP).

Management has selected the assumptions used in the projections of plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with US accounting standards (US GAAP). We are not expressing any opinion on these assumptions.

In our opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The calculations have been made in accordance with the requirements of US accounting standards (US GAAP), reflecting application of the Company's accounting policies described in this report.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.



P. Charles Allegro
FCIA, FSA

June 1, 2012
Date



Allen Hornung
FCIA, FSA

June 1, 2012
Date

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# APPENDIX A

## Sensitivity of Results

The estimated impact on accrual costs of positive and negative "shocks" to the plan's assets and benefit obligations are given in this appendix. These "shocks" are assumed to occur at the end of 2013 in all scenarios.

Amounts in this appendix reflect only Enbridge Gas Distribution Inc.'s share of costs.

### Equity markets return +/- 20% more than expected

This scenario assumes that equity markets return 20% more or less than baseline assumptions, resulting in a return over 2013 that is 12.0%[2] higher or lower than our baseline assumption of 6.37%.

**Table A.1: Positive Asset Shock in 2013 (+20% equity return)**

| | Accrual Costs – EGDI Only ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $36.6 | - |
| 2014 | $17.5 | *($14.0)* |
| 2015 | $16.4 | *($11.5)* |
| 2016 | $15.0 | *($9.8)* |
| 2017 | $13.6 | *($8.5)* |

**Table A.2: Negative Asset Shock in 2013 (-20% equity return)**

| | Accrual Costs – EGDI Only ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $36.6 | - |
| 2014 | $45.8 | *$14.3* |
| 2015 | $40.4 | *$12.5* |
| 2016 | $35.8 | *$11.0* |
| 2017 | $31.6 | *$9.5* |

[2] EGD RPP assets include a 60.0% allocation to growth assets, multiplied by +/- 20% equals return adjustment of +/- 12.0%. SERP and SSERP assets include a 35% allocation to growth assets, so the adjustment for these plans is +/- 7.0%.

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## Yield curve shift of +/- 1%

This scenario assumes a year-end 2013 parallel shift in the yield curve which benefit obligation discount rates are based on. We have assumed this change would not impact the fixed income portion of the plan's assets. In other words, this sensitivity is intended to represent a pure obligation shock (resulting from any economic or demographic experience different than expected), whereas the previous sensitivity was a pure asset shock.

**Table A.3: Positive Obligation Shock in 2013 (+1% shift in yield curve)**

| | Accrual Costs – EGDI Only ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $36.6 | - |
| 2014 | $19.1 | *($12.4)* |
| 2015 | $19.3 | *($8.6)* |
| 2016 | $19.6 | *($5.2)* |
| 2017 | $19.4 | *($2.7)* |

**Table A.4: Negative Obligation Shock in 2013 (-1% shift in yield curve)**

| | Accrual Costs – EGDI Only ($millions) | |
|---|---|---|
| | **US GAAP P&L CHARGE** | ***Δ from baseline*** |
| 2013 | $36.6 | - |
| 2014 | $41.2 | *$9.7* |
| 2015 | $34.6 | *$6.7* |
| 2016 | $28.9 | *$4.1* |
| 2017 | $23.7 | *$1.6* |

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# APPENDIX B

## Total Accrual Costs

The accrual costs shown on pages 5 and 6, and in Appendix A, are only in respect of direct charges to the P&L statement. Under US GAAP, additional charges (primarily in respect of recognizing actuarial gains and losses) are reflected in the OCI statement. This appendix includes estimates of both direct P&L charges and indirect OCI charges over 2013 through 2017.

Amounts in this appendix reflect only Enbridge Gas Distribution Inc.'s share of costs.

Accrual Costs – US GAAP ($Millions) – EGDI Only

| | P&L CHARGE | OCI CHARGE | TOTAL CHARGE |
|---|---|---|---|
| 2013 Charge | $36.6 | $4.6 | $41.2 |
| 2014 Charge | $31.5 | $4.9 | $36.4 |
| 2015 Charge | $27.9 | $5.2 | $33.1 |
| 2016 Charge | $24.8 | $5.5 | $30.3 |
| 2017 Charge | $22.1 | $5.8 | $27.9 |

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# APPENDIX C

## Required Disclosures

### Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The information presented in this report has been prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

- The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions and accounting policies selected by Management;

- We have projected assets forward using benchmark asset returns (net of expenses) to March 31, 2012 and our best estimate of asset returns (net of expenses) after March 31, 2012. Projected future cash flows have also been incorporated.

- We have projected benefit obligations forward using the expected cost of benefits accruing over 2012 through 2016, reflecting interest over each period and adjusting year-end 2012 benefit obligations to reflect the economic environment as at March 31, 2012. Benefit obligations in future periods are projected forward with these same March 31, 2012 assumptions and methodology. Projected future cash flows have also been incorporated.

- The starting point for our asset projection was the market value of assets as of December 31, 2011, shown in Appendix D.

- Our calculations are based on the assumptions and methodology described in Appendix E. The discount rate assumption has been updated from the rate used in the December 31, 2011 valuation to reflect market conditions as at March 31, 2012 and the CIA discount rate methodology proposed in September 2011.

- Our calculations are based on extrapolations of a valuations performed using membership data as at December 31, 2011. The membership data used in our projections and calculations is summarized in Appendix F.

- Our calculations reflect the provisions of the Plan as at March 31, 2012. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix G.

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## Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent March 31, 2012 which, in our opinion, would have a material impact on the results of the projection.

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# APPENDIX D

## Plan Assets

The DB assets of the EGD RPP and the invested assets of the SERP and SSERP are held in trust by CIBC Mellon. SERP and SSERP assets also include the refundable tax account held with CRA. We have relied upon the audited fund statements provided by PriceWaterhouseCoopers LLP as at December 31, 2011.

The starting point for our projections of assets were the market value of each plan's assets as at December 31, 2011.

### Investment Policy

The plans' administrator adopted a statement of investment policy and procedures, last revised in 2011. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the plans' investment objectives. A significant component of this investment policy is the asset mix.

The target and actual asset mix for the EGD RPP is provided for information purposes:

| | Investment Policy – EGD RPP | |
|---|---|---|
| | **Target @ 3.31.2012** | **Actual @ 12.31.2011** |
| Canadian equities | 21.0% | 18.8% |
| Global equities | 17.0% | 29.5% |
| Emerging market equities | 6.5% | |
| Fixed income – universe | 30.0% | 32.7% |
| Fixed income – real return | 10.0% | 11.6% |
| Infrastructure | 9.0% | 6.4% |
| Real estate | 6.5% | 0.0% |
| Cash and cash equivalents | 0.0% | 1.0% |
| | 100% | 100% |

Because of the mismatch between the EGD RPP assets (which are invested in accordance with the above investment policy) and the liabilities (which tend to behave like long bonds) the financial position of the EGD RPP will fluctuate over time. These fluctuations could be significant and could cause the EGD RPP to become under, or over, funded.

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# APPENDIX E

## Accounting Methods and Assumptions

### Accounting Methods

#### *Valuation of Assets*

The market value of assets is used to determine pension costs.

For purposes of these estimates, we have projected the market value of EGD RPP DB assets at December 31, 2011 using benchmark asset returns (net of all expenses) of 3.88% from January 1, 2012 to March 31, 2012, and our best estimate of asset returns (net of all expenses) of 4.78% from April 1, 2012 to December 31, 2012. Therefore, the annual rate of return over 2012 for the EGD RPP (net of all expenses) assumed in our projection is 8.66%. The annual rate of return over 2012 in respect of the SERP and SSERP was one half of this amount, or 4.33%.

Asset returns after December 31, 2012 are assumed to be 6.37% per year for the EGD RPP, and 3.63% per year for the SERP and SSERP. These assumptions were provided to us by Management.

Estimated future cash flows have been incorporated into our projections.

**Actual assets over year-end 2012 through 2016 will differ from these estimates.**

#### *Valuation of Benefit Obligations and Current Service Cost*

For purposes of these estimates, we have continued to use the projected unit credit method for the valuation of benefit obligations and current service cost of the plans. The objective under this method is to expense each participant's benefits under the plans as they would accrue; taking into consideration future salary increases and the plans' benefit allocation formula. Thus, the total pension, to which each participant is expected to become entitled at retirement, is broken down into units, each associated with a year of past or future credited service.

The benefit deemed to accrue for an individual during a fiscal year is the excess of the accrued benefit for valuation purposes at the end of the fiscal year over the accrued benefit for valuation purposes at the beginning of the fiscal year. Both accrued benefits are calculated from the same projections to the various anticipated separation dates. An individual's benefit obligation is the present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the service cost is the present value of the benefit deemed to accrue in the fiscal year.

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The plan's service cost is the sum of the individual service costs, and the plan's benefit obligation is the sum of the individual benefit obligations for all participants under the plan.

There is no current service cost in respect of the SERP or SSERP.

## Accounting Policies

### *Accounting Standards Transition*

For year-end 2011 the Company's financial reports were in accordance with Canadian GAAP accounting standards.

The Company adopted US GAAP accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of US GAAP financial statements, the Company transitioned to US GAAP from Canadian GAAP on January 1, 2011. On that date, a transition adjustment was made to retained earnings to bring the existing Canadian GAAP balances in line with the requirements of US GAAP. The Company continued to report under Canadian GAAP for the fiscal year ending December 31, 2011. At January 1, 2012, the company will no longer report under current Canadian GAAP and will commence with reporting entirely under US GAAP for the fiscal year ending December 31, 2012.

### *Measurement Date*

The Company's fiscal year end date is December 31, and the measurement date for plan assets and obligations under US GAAP is also December 31.

### *Attribution*

Under US GAAP, obligations are attributed to the period beginning on the employee's date of joining the plan and ending on the earlier of the date of termination, death or retirement.

### *Amortizations of Prior Service Costs and Gains and Losses*

The Company has elected to amortize past service costs resulting from plan amendments to the EGD RPP on a linear basis over the average remaining service period of active members expected to receive benefits under the plan at the time the amendments were made.

Cumulative gains and losses in excess of 10% of the greater of the PBO or market value of plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan (10.1 years for the EGD RPP, 4.3 years for the SERP and 14.7 years for the SSERP as at December 31, 2011).

## Accounting Assumptions

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The following assumptions, provided to us by Management, were used in valuing the benefit obligations under the plan and the employer's pension cost.

| | |
|---|---|
| Measurement date | December 31 |
| Discount rate | 4.33% |
| Expected rate of return on invested assets – EGD RPP | 7.00% |
| Expected rate of return on invested assets – SERP/SSERP | 3.20% |
| Inflation | 2.25% |
| Increases in pensionable earnings | 3.50% |
| Increases in the YMPE | 2.75% |
| Increases in maximum pension permitted under the *Income Tax Act* | 2.75% |
| Indexation of pensions in payment | 1.24% per year in respect of Contributory service, 1.13% per year in respect of Non-Contributory and Senior Manager service |
| Mortality | UP-1994 generational mortality table |
| Disability | No allowance for future disabilities |
| Withdrawal | See tables of sample rates |
| Expenses | Implicit in long-term rate of return on assets |
| Retirement | See table of sample rates |
| Percentage with spouse | 80% married |
| Age difference | A male is assumed to be 2 years older than his spouse |
| Headcount | No allowance made for headcount growth |

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Sample rates from the age related tables are summarized below:

| Age | Termination - Male | Termination - Female | Retirement |
|---|---|---|---|
| 20 | 5.0% | 9.5% | 0.0% |
| 25 | 5.0% | 13.0% | 0.0% |
| 30 | 5.0% | 11.0% | 0.0% |
| 35 | 4.6% | 8.5% | 0.0% |
| 40 | 3.0% | 4.0% | 0.0% |
| 45 | 2.5% | 3.9% | 0.0% |
| 50 | 1.5% | 2.8% | 0.0% |
| 55 | 0.0% | 0.0% | 5.0% |
| 56 | 0.0% | 0.0% | 5.0% |
| 57 | 0.0% | 0.0% | 7.5% |
| 58 | 0.0% | 0.0% | 7.5% |
| 59 | 0.0% | 0.0% | 10.0% |
| 60 | 0.0% | 0.0% | 20.0% |
| 61 | 0.0% | 0.0% | 20.0% |
| 62 | 0.0% | 0.0% | 20.0% |
| 63 | 0.0% | 0.0% | 20.0% |
| 64 | 0.0% | 0.0% | 20.0% |
| 65 | 0.0% | 0.0% | 100.0% |

A 20% retirement rate is assumed in lieu of the above rate in the year in which a member qualifies for early retirement with an unreduced pension and in each subsequent year until age 65.

**Our assumptions are based on the economic environment as of March 31, 2012, the discount rate methodology proposed by the CIA in September 2011, and input provided by the Company for the December 31, 2011 accounting valuation. Assumptions as at year-end 2012 through 2016 will reflect the economic environment and input from the Company at those times, and may differ from those used in these projections.**

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# APPENDIX F

## Membership Data

### Analysis of Membership Data at December 31, 2011

For purposes of these estimates, we have based our projections on membership data as at December 31, 2011 for each plan, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix E.

Membership data for the EGD RPP as at December 31, 2011 are summarized below.

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| | 12.31.2011 (EGD RPP) |
|---|---|
| **Active Members Accruing Defined Benefit Service (Non-SMEs)** | |
| Number | 1,872 |
| Total base earnings at the valuation date | $141,763,000 |
| Average base earnings at the valuation date | $75,700 |
| Average years of Non-SME DB pensionable service | 12.4 years |
| Average age | 45.4 years |
| **Active Members Accruing Defined Benefit Service (SMEs)** | |
| Number | 33 |
| Total base earnings at the valuation date | $6,836,000 |
| Average base earnings at the valuation date | $207,200 |
| Average years of SME DB pensionable service | 3.4 years |
| Average age | 50.7 years |
| **Suspended Defined Benefit Members Accruing Defined Contribution Service** | |
| Number | 73 |
| Total base earnings at the valuation date | $6,314,000 |
| Average base earnings at the valuation date | $86,500 |
| Average years of Non-SME DB pensionable service | 5.6 years |
| Average age | 46.0 years |
| **Other Suspended Defined Benefit Members (Non-SMEs)** | |
| Number | 18 |
| Total base earnings at the valuation date | $1,962,000 |
| Average base earnings at the valuation date | $109,000 |
| Average years of Non-SME DB pensionable service | 4.3 years |
| Average age | 40.6 years |
| **Other Suspended Defined Benefit Members (SMEs)** | |
| Number | 16 |
| Total base earnings at the valuation date | $4,234,000 |
| Average base earnings at the valuation date | $264,600 |
| Average years of Non-SME DB pensionable service | 7.2 years |
| Average years of SME DB pensionable service | 1.8 years |
| Average age | 44.3 years |

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| | 12.31.2011 (EGD RPP) |
|---|---|
| **Active Defined Contribution Members without Defined Benefit Service** | |
| Number | 197 |
| Total base earnings at the valuation date | $16,347,000 |
| Average base earnings at the valuation date | $83,000 |
| Average age | 41.4 years |
| **Suspended Defined Contribution Members without Defined Benefit Service** | |
| Number | 5 |
| Total base earnings at the valuation date | $667,000 |
| Average base earnings at the valuation date | $133,000 |
| Average age | 36.5 years |
| **Deferred Pensioners** | |
| Number | 191 |
| Total annual pension | $936,000 |
| Average annual pension | $4,900 |
| Average age | 48.5 years |
| **Pensioners and Survivors** | |
| Number | 1,458 |
| Total annual lifetime pension | $29,650,000 |
| Average annual lifetime pension | $20,300 |
| Total annual temporary pension | $1,878,000 |
| Average annual temporary pension | $7,000 |
| Average age | 71.9 years |

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# APPENDIX G

## Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the plans in effect on March 31, 2012. The plans have not been amended since December 31, 2011..

### EGD RPP - DB Component

The following is a summary of the main provisions of the DB component of the EGD RPP in effect on March 31, 2012. This summary is not intended as a complete description of the EGD RPP.

| | |
|---|---|
| **Background** | The EGD RPP became effective January 1, 1971.<br>Benefits are based on a set formula and are entirely paid for by Enbridge.<br>Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service.<br>In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan. |
| **Eligibility for Membership** | New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component. |
| **Vesting** | All employees are immediately vested as of July 1, 2011. |
| **Employee Contributions** | No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required. |
| **Retirement Dates** | Normal Retirement Date<br>• The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday.<br>Early Retirement Date<br>• A member becomes immediately vested and may choose to retire as early as age 55. |

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| | |
|---|---|
| **Normal Retirement Pension** | **Contributory Service:**<br>2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service;<br>less<br>100% of the Contributory Canada Pension Plan Entitlement.<br>**Non-Contributory Service:**<br>1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service;<br>less<br>50% of the Non-Contributory Canada Pension Plan Entitlement;<br>**SME Credited Service:**<br>2.0% of Final Three Year Average Earnings multiplied by years of SME credited service. |
| **Final Five Year Average Earnings** | Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees. |
| **Final Three Year Average Earnings** | Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by 3. |
| **Canada Pension Plan Entitlement** | **Contributory Service:**<br>One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years.<br>**Non-Contributory Service:**<br>Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing a dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%. |

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| | |
|---|---|
| **Early Retirement Pension** | The following benefits apply if a member retires early with the Company's consent:<br>• If the member has attained age 60, the pension payable is as described above in the Normal Retirement section.<br>• If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement.<br>• If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement.<br>• If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions.<br>If a member retires without company consent the benefit is actuarially equivalent to the benefit payable at age 65. |
| **Maximum Pension** | The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of:<br>• 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and<br>• $2,646.67, or such other maximum as may apply from time to time<br>indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the *Income Tax Act* rules. |
| **Indexation of Pensions in Payment** | On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership.<br>Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis. |

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| | |
|---|---|
| **Death Benefits** | **Death Before Eligible for Early Retirement**<br>If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service.<br>**Death After Eligibility for Early Retirement**<br>If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service.<br>**Death After Retirement**<br>The death benefit payable is in accordance with the form elected.<br>The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members. |
| **Termination Benefits** | If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP. |
| **Disability Benefits** | Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled. |

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## EGD RPP - DC Component

The following is a summary of the main provisions of the DC component of the EGD RPP in effect on March 31, 2012. This summary is not intended as a complete description of the EGD RPP.

| | |
|---|---|
| **Background** | The DC component of the EGD RPP became effective July 1, 2001.<br>Employer contributions are remitted to individual member accounts and are credited with interest.<br>Members receive the balance of their individual employer account upon termination, death or retirement. |
| **Eligibility for Membership** | New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component. |
| **Vesting** | All employees are immediately vested as of July 1, 2011. |
| **Employee Contributions** | No employee contributions are required or permitted. |
| **Employer Contributions** | Employer contributions to the DC component are based on a member's points.<br>• less than 40 points: 4.0% of pensionable earnings[3]<br>• 40 to 60 points: 5.5% of pensionable earnings<br>• greater than 60 points: 7.0% of pensionable earnings |
| **Maximum Contribution** | The employer contributions are limited to the amounts under the ITA. |
| **Pensionable Earnings** | Base salary plus 50% of actual bonus received. |

[3] For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

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## SERP / SSERP

The following is a summary of the main provisions of the SERP and SSERP in effect on March 31, 2012. This summary is not intended as a complete description of the SERP or SSERP.

| | |
|---|---|
| **Background - SERP** | The SERP became effective November 19, 1987. It provides to designated employees benefit amounts that would otherwise be payable under the EGD RPP beyond the ITA maximum pension limit on service accrued prior to January 1, 2000.<br>The SERP is closed to new entrants. |
| **Background - SSERP** | The SSERP became effective November 19, 1984. Only members designated by Enbridge Gas Distribution Inc. were able to join the SSERP.<br>The SSERP is closed to new entrants, and the only remaining members are pensioners and survivors. |

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MERCER

Mercer (Canada) Limited
222 - 3rd Avenue SW Suite 1200 Calgary,
Alberta T2P 0B4
+1 403 269 4945



MARSH & McLENNAN COMPANIES

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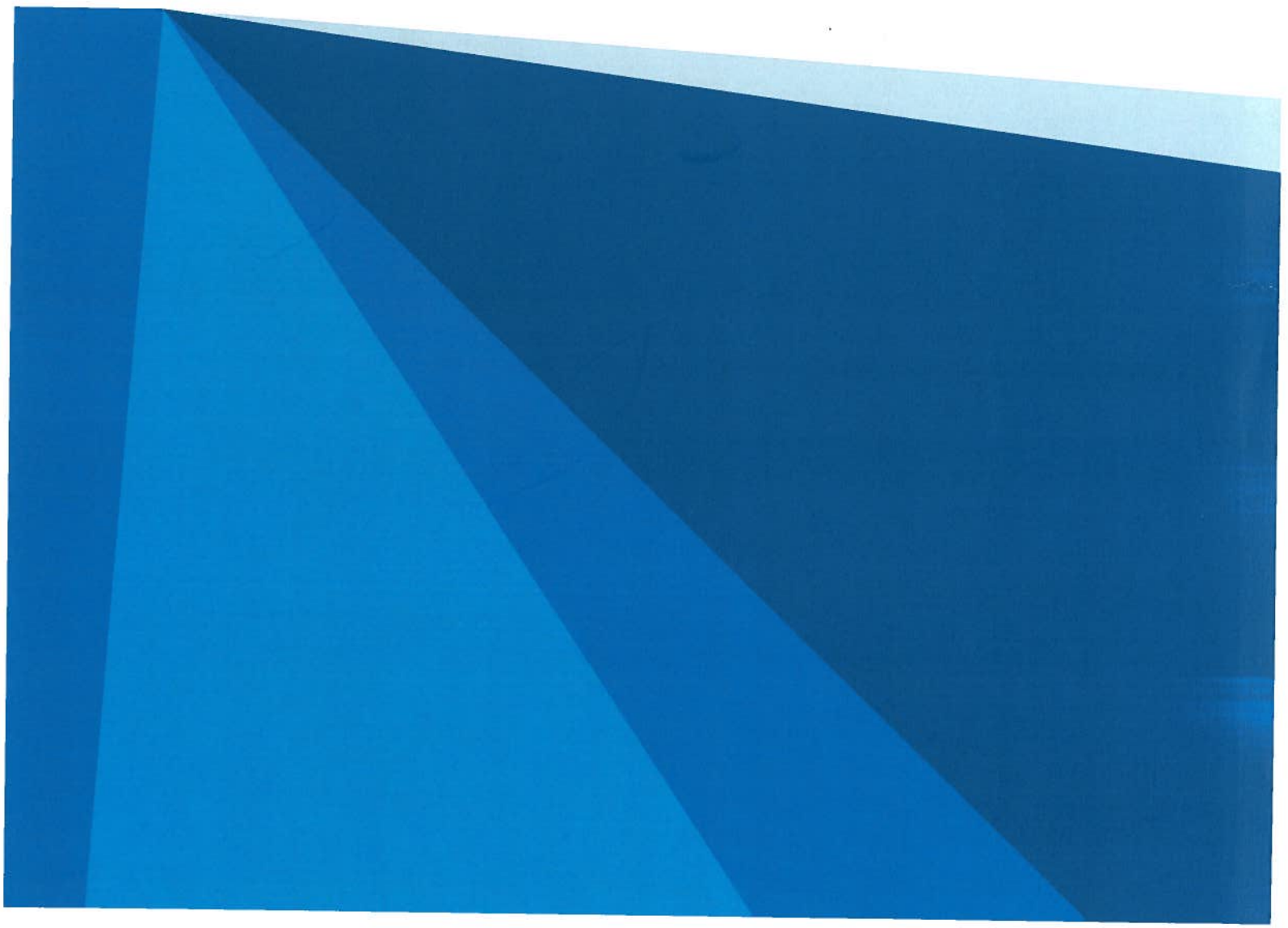
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# UPDATED ESTIMATED 2013 - 2017 CASH FUNDING COSTS

## EGD PENSION PLANS

01 JUNE 2012



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**Note to reader regarding actuarial valuations and projections:**

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A projection is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

Should the plan be wound up, the going-concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the projection date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions used in this projection, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a projection or a valuation report.

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# 1

# Introduction

## Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the minimum cash funding requirements over 2013 to 2017 for:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SSERP"),

based on economic conditions at March 31, 2012. Actual cash funding requirements in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of 2013 to 2017 pension costs from ratepayers.

Note that information contained in this report reflects all assets, liabilities and costs in respect of all employers participating in the EGD RPP, except where specifically noted.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

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# Background Information

## Determination of Contribution Requirements

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Minimum required cash funding to the DB component is determined based on actuarial valuations filed with the Financial Services Commission of Ontario ("FSCO") and the Canada Revenue Agency ("CRA"). Valuations may be filed at the plan sponsor's discretion, but must be filed at least once every three years. For purposes of this analysis, we have assumed EGD will file an actuarial valuation with the pension regulators annually over 2013 through 2017.

The SERP and SSERP are closed supplemental pension arrangements sponsored by Enbridge Gas Distribution Inc. and are relatively small compared to the EGD RPP. Projected costs for the SERP and SSERP have been included here for completeness.

We have conducted an actuarial valuation of all three plans for management information purposes as at December 31, 2011 that was not filed with FSCO or CRA. These valuations are the basis for the projections contained herein.

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## Historical Funding

Due to historical plan surplus in the DB component of the EGD RPP, DB cash contributions have not been required to the EGD RPP for the 10 years prior to 2012. In addition, the DB surplus has been used to cover contributions to the DC component over this period. Historical costs to the DB and DC components of the EGD RPP are summarized below.

| | DB Service Cost | DC Service Cost | Total Plan Service Cost | Total Plan Contribution |
|---|---|---|---|---|
| 2002 | $8.5M | $0.5M | $9.0M | $0 |
| 2003 | $8.6M | $0.7M | $9.3M | $0 |
| 2004 | $8.9M | $0.8M | $9.7M | $0 |
| 2005 | $9.9M | $0.8M | $10.7M | $0 |
| 2006 | $12.1M | $1.1M | $13.2M | $0 |
| 2007 | $14.4M | $1.3M | $15.7M | $0 |
| 2008 | $15.7M | $1.4M | $17.1M | $0 |
| 2009 | $14.8M | $1.4M | $16.2M | $0 |
| 2010 | $14.7M | $1.4M | $16.1M | $0 |
| 2011 | $16.3M | $1.4M | $17.7M | $0 |
| **Total** | **$123.9M** | **$10.8M** | **$134.7M** | **$0** |

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# Financial Results

## Financial Position at December 31, 2011 and Projected Future Financial Positions

We have projected the results of the December 31, 2011 actuarial valuations of the plans forward to each of the years ending 2012 through 2016. The purpose of these projections is to estimate minimum cash funding requirements for 2013 through 2017. **The projections are based on the economic environment as at March 31, 2012 and assumptions described in Appendix D. The actual economic environment as at each of the years ending 2012 through 2016 and actual plan experience over this period may differ significantly from these assumptions.**

For simplicity, we have excluded assets and liabilities with respect to the DC provision of the EGD RPP in the balance sheets shown below.

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## *Projected Going-Concern Balance Sheets*

The table below details the actual going-concern financial position of the plans as at December 31, 2011, as well as the projected position of the plans at each of year-end 2012 through 2016, assuming plan experience unfolds according to the assumptions described in Appendix D.

Going-Concern Financial Position ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| **12.31.2011 (Actual)** | | | | |
| Assets | $715.6 | $15.5 | $7.7 | $738.8 |
| Liabilities | $704.2 | $16.8 | $5.2 | $726.2 |
| Funding excess (shortfall) | $11.4 | ($1.3) | $2.5 | $12.6 |
| **12.31.2012 (Projected)** | | | | |
| Assets | $758.6 | $15.8 | $7.5 | $781.9 |
| Liabilities | $728.7 | $16.4 | $4.8 | $749.9 |
| Funding excess (shortfall) | $29.9 | ($0.6) | $2.7 | $32.0 |
| **12.31.2013 (Projected)** | | | | |
| Assets | $811.8 | $15.7 | $7.2 | $834.7 |
| Liabilities | $753.8 | $16.0 | $4.5 | $774.3 |
| Funding excess (shortfall) | $58.0 | ($0.3) | $2.7 | $60.4 |
| **12.31.2014 (Projected)** | | | | |
| Assets | $863.1 | $15.4 | $6.9 | $885.4 |
| Liabilities | $779.6 | $15.6 | $4.0 | $799.2 |
| Funding excess (shortfall) | $83.5 | ($0.2) | $2.9 | $86.2 |
| **12.31.2015 (Projected)** | | | | |
| Assets | $913.0 | $15.0 | $6.5 | $934.5 |
| Liabilities | $806.1 | $15.1 | $3.6 | $824.8 |
| Funding excess (shortfall) | $106.9 | ($0.1) | $2.9 | $109.7 |
| **12.31.2016 (Projected)** | | | | |
| Assets | $962.0 | $14.5 | $6.1 | $982.6 |
| Liabilities | $833.3 | $14.5 | $3.1 | $850.9 |
| Funding excess (shortfall) | $128.7 | $0.0 | $3.0 | $131.7 |

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## *Projected Solvency Balance Sheet*

The table below details the actual solvency financial position of the EGD RPP as at December 31, 2011, as well as the projected position of the plans at each of year-end 2012 through 2016, assuming plan experience unfolds according to the assumptions described in Appendix D.

The solvency measure has historically had no impact on cash funding requirements for the SERP or SSERP, and has been excluded from this report for simplicity.

Solvency Financial Position ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| **12.31.2011 (Actual)** | | | | |
| Assets | $715.0 | n/a | n/a | n/a |
| Liabilities | $834.3 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($119.3) | n/a | n/a | n/a |
| **12.31.2012 (Projected)** | | | | |
| Assets | $758.0 | n/a | n/a | n/a |
| Liabilities | $853.4 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($95.4) | n/a | n/a | n/a |
| **12.31.2013 (Projected)** | | | | |
| Assets | $811.2 | n/a | n/a | n/a |
| Liabilities | $886.5 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($75.3) | n/a | n/a | n/a |
| **12.31.2014 (Projected)** | | | | |
| Assets | $862.5 | n/a | n/a | n/a |
| Liabilities | $920.8 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($58.3) | n/a | n/a | n/a |
| **12.31.2015 (Projected)** | | | | |
| Assets | $912.4 | n/a | n/a | n/a |
| Liabilities | $956.2 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($43.8) | n/a | n/a | n/a |
| **12.31.2016 (Projected)** | | | | |
| Assets | $961.4 | n/a | n/a | n/a |
| Liabilities | $992.8 | n/a | n/a | n/a |
| Solvency excess (deficiency) | ($31.4) | n/a | n/a | n/a |

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## Summary of Minimum Required Cash Costs

Based on the projected financial positions above, the resulting minimum required cash funding for the plans over 2013 – 2017 are summarized below.

Cash Costs ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| **2013 (Projected)** | | | | |
| DB going-concern service cost | $17.7 | $0.0 | $0.0 | $17.7 |
| DC service cost | $1.3 | $0.0 | $0.0 | $1.3 |
| Solvency amortization payments | $21.1 | $0.3 | $0.0 | $21.4 |
| Total minimum cash contribution | $40.1 | $0.3 | $0.0 | $40.4 |
| **2014 (Projected)** | | | | |
| DB going-concern service cost | $18.3 | $0.0 | $0.0 | $18.3 |
| DC service cost | $1.4 | $0.0 | $0.0 | $1.4 |
| Solvency amortization payments | $16.6 | $0.1 | $0.0 | $16.7 |
| Total minimum cash contribution | $36.3 | $0.1 | $0.0 | $36.4 |
| **2015 (Projected)** | | | | |
| DB going-concern service cost | $19.0 | $0.0 | $0.0 | $19.0 |
| DC service cost | $1.4 | $0.0 | $0.0 | $1.4 |
| Solvency amortization payments | $12.9 | $0.1 | $0.0 | $13.0 |
| Total minimum cash contribution | $33.3 | $0.1 | $0.0 | $33.4 |
| **2016 (Projected)** | | | | |
| DB going-concern service cost | $19.6 | $0.0 | $0.0 | $19.6 |
| DC service cost | $1.5 | $0.0 | $0.0 | $1.5 |
| Solvency amortization payments | $9.7 | $0.1 | $0.0 | $9.8 |
| Total minimum cash contribution | $30.8 | $0.1 | $0.0 | $30.9 |
| **2017 (Projected)** | | | | |
| DB going-concern service cost | $20.3 | $0.0 | $0.0 | $20.3 |
| DC service cost | $1.5 | $0.0 | $0.0 | $1.5 |
| Solvency amortization payments | $6.9 | $0.0 | $0.0 | $6.9 |
| Total minimum cash contribution | $28.7 | $0.0 | $0.0 | $28.7 |

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## *Enbridge Gas Distribution Inc.'s Share of Funding*

In addition to Enbridge Gas Distribution Inc., two other smaller employers participate in the EGD RPP. The following tables provide the same results as those on page 7, but are only in respect of Enbridge Gas Distribution Inc.'s share of costs[1].

Cash Costs – EGDI Only ($Millions)

| | EGD RPP | SERP | SSERP | TOTAL |
|---|---|---|---|---|
| **2013 (Projected)** | | | | |
| DB going-concern service cost | $16.7 | $0.0 | $0.0 | $16.7 |
| DC service cost | $1.2 | $0.0 | $0.0 | $1.2 |
| Solvency amortization payments | $20.6 | $0.3 | $0.0 | $20.9 |
| Total minimum cash contribution | $38.5 | $0.3 | $0.0 | $38.8 |
| **2014 (Projected)** | | | | |
| DB going-concern service cost | $17.2 | $0.0 | $0.0 | $17.2 |
| DC service cost | $1.2 | $0.0 | $0.0 | $1.2 |
| Solvency amortization payments | $16.2 | $0.1 | $0.0 | $16.3 |
| Total minimum cash contribution | $34.6 | $0.1 | $0.0 | $34.7 |
| **2015 (Projected)** | | | | |
| DB going-concern service cost | $17.8 | $0.0 | $0.0 | $17.8 |
| DC service cost | $1.3 | $0.0 | $0.0 | $1.3 |
| Solvency amortization payments | $12.5 | $0.1 | $0.0 | $12.6 |
| Total minimum cash contribution | $31.6 | $0.1 | $0.0 | $31.7 |
| **2016 (Projected)** | | | | |
| DB going-concern service cost | $18.5 | $0.0 | $0.0 | $18.5 |
| DC service cost | $1.3 | $0.0 | $0.0 | $1.3 |
| Solvency amortization payments | $9.4 | $0.1 | $0.0 | $9.5 |
| Total minimum cash contribution | $29.2 | $0.1 | $0.0 | $29.3 |
| **2017 (Projected)** | | | | |
| DB going-concern service cost | $19.1 | $0.0 | $0.0 | $19.1 |
| DC service cost | $1.4 | $0.0 | $0.0 | $1.4 |
| Solvency amortization payments | $6.8 | $0.0 | $0.0 | $6.8 |
| Total minimum cash contribution | $27.3 | $0.0 | $0.0 | $27.3 |

[1] Note that Enbridge Gas Distribution Inc. is the only employer participating in the SERP and SSERP.

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## Important to Note

The purpose of this report is to estimate the minimum required cash contributions over 2013 through 2017. However, the occurrence and/or level of required contributions in 2013 through 2017 is highly dependent on:

- Financial market returns after March 31, 2012;
- Changes in long-term government bond yields after March 31, 2012;
- Changes to the prescribed spread used to determine solvency discount rates after March 31, 2012; and
- Actual plan demographic experience.

These items will cause actual contributions over 2013 through 2017 to differ from the estimates provided in this report.

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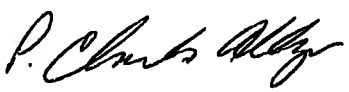
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## Actuarial Opinion

In our opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The assumptions are appropriate; and
- The methods employed in the projections are appropriate.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Ontario)*.



P. Charles Allegro
FCIA, FSA

June 1, 2012
Date



Allen Hornung
FCIA, FSA

June 1, 2012
Date

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# APPENDIX A

## Sensitivity of Results

The estimated impact on cash costs of positive and negative "shocks" to the plan's assets and liabilities are given in this appendix. These "shocks" are assumed to occur at the end of 2013 in all scenarios.

Amounts in this appendix reflect only Enbridge Gas Distribution Inc.'s share of costs.

### Equity markets return +/- 20% more than expected

This scenario assumes that equity markets return 20% more or less than baseline assumptions, resulting in a return over 2013 that is 12.0%[2] higher or lower than our baseline assumption of 6.37%.

**Table A.1: Positive Asset Shock in 2013 (+20% equity return)**

| | Cash / Funding Costs – EGDI Only ($millions) | |
|---|---|---|
| | TOTAL CASH COST | *Δ from baseline* |
| 2013 | $38.8 | - |
| 2014 | $3.4 | *($31.3)* |
| 2015 | $14.3 | *($17.4)* |
| 2016 | $15.0 | *($14.3)* |
| 2017 | $15.5 | *($11.8)* |

**Table A.2: Negative Asset Shock in 2013 (-20% equity return)**

| | Cash / Funding Costs – EGDI Only ($millions) | |
|---|---|---|
| | TOTAL CASH COST | *Δ from baseline* |
| 2013 | $38.8 | - |
| 2014 | $54.7 | *$20.0* |
| 2015 | $48.4 | *$16.7* |
| 2016 | $43.3 | *$14.0* |
| 2017 | $38.8 | *$11.5* |

[2] EGD RPP assets include a 60.0% allocation to growth assets, multiplied by +/- 20% equals return adjustment of +/- 12.0%. SERP and SSERP assets include a 35% allocation to growth assets, so the adjustment for these plans is +/- 7.0%.

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## Yield curve shift of +/- 1%

This scenario assumes a year-end 2013 parallel shift in the yield curve which liability discount rates are based on. We have assumed this change would not impact the fixed income portion of the plan's assets. In other words, this sensitivity is intended to represent a pure liability shock (resulting from any economic or demographic experience different than expected), whereas the previous sensitivity was a pure asset shock.

**Table A.3: Positive Liability Shock in 2013 (+1% shift in yield curve)**

| | Cash / Funding Costs – EGDI Only ($millions) | |
|---|---|---|
| | **TOTAL CASH COST** | ***Δ from baseline*** |
| 2013 | $38.8 | - |
| 2014 | - | *($34.7)* |
| 2015 | - | *($31.7)* |
| 2016 | $2.8 | *($26.5)* |
| 2017 | $17.4 | *($9.9)* |

**Table A.4: Negative Liability Shock in 2013 (-1% shift in yield curve)**

| | Cash / Funding Costs – EGDI Only ($millions) | |
|---|---|---|
| | **TOTAL CASH COST** | ***Δ from baseline*** |
| 2013 | $38.8 | - |
| 2014 | $64.0 | *$29.3* |
| 2015 | $55.0 | *$23.3* |
| 2016 | $47.4 | *$18.1* |
| 2017 | $41.0 | *$13.7* |

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# APPENDIX B

## Required Disclosures

### Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- They have been prepared in accordance with applicable pension legislation and based on methods and actuarial assumptions that are consistent with actuarial standards of practice in Canada;
- We have reflected a margin for adverse deviations in our going concern projection by reducing the going-concern discount rate by 0.62% per year; and
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations;
  - Certain excludable benefits were excluded from the solvency liabilities; and
  - The solvency financial position was determined on a projected market value basis.
- We have projected assets forward from December 31, 2011 using benchmark asset returns (net of expenses) to March 31, 2012 and our best estimate of asset returns (net of expenses) after March 31, 2012. Projected future cash flows have also been incorporated.
- We have projected liabilities forward using the expected cost of benefits accruing over 2012 through 2016, reflecting interest over each period and adjusting year-end 2012 liabilities to reflect the economic environment as at March 31, 2012. Liabilities in future periods are projected forward with these same March 31, 2012 assumptions and methodology. Projected future cash flows have also been incorporated.

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- The starting point for our asset projection was the market value of assets as of December 31, 2011, shown in Appendix C.

- Our calculations are based on the assumptions and methodology described in Appendix D. We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2011. The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions as at March 31, 2012. Emerging experience will affect the funded position of the Plan.

- Our calculations are based on an extrapolation of a valuation performed using membership data as at December 31, 2011. The membership data used in our calculations is summarized in Appendix E.

- Our calculations reflect the provisions of the Plan as at March 31, 2012. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix F.

## Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent March 31, 2012 which, in our opinion, would have a material impact on the results of the projection.

## Next Required Valuation

In accordance with pension benefits legislation, the next actuarial valuation of the EGD RPP to be filed with FSCO and CRA will be required as at a date not later than December 31, 2012, or as at the date of an earlier amendment to the Plan. Valuations of the SERP and SSERP are not required to be filed with the pension regulators.

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## Gain and Loss Analysis

A reconciliation of the actual going-concern financial position of the EGD RPP between December 31, 2011 and the projected going-concern financial position at December 31, 2012 follows:

| Reconciliation of financial status ($millions) | 2012 |
|---|---|
| Funding excess (shortfall) as at December 31, 2011 | $11.4 |
| Interest on funding excess (funding shortfall) at 5.75% per year | $0.7 |
| DB contributions drawn from funding excess, with interest | - |
| DC contributions drawn from funding excess, with interest | - |
| Net investment return different than expected | $17.8 |
| Funding excess (shortfall) as at December 31, 2012 | $29.9 |

Future periods are assumed to unfold in accordance with the assumptions described in Appendix D, therefore no additional gains or losses are anticipated for purposes of this analysis.

## Solvency Incremental Cost

The solvency incremental cost is an estimate of the present value of the projected change in the EGD RPP solvency liabilities from December 31, 2011 to December 31, 2012 (before assumption changes), adjusted for benefit payments expected to be made over the period.

The estimated 2012 solvency incremental cost determined in this projection is $36.9M.

## Discount Rate Sensitivity

The following table summarises the effect on the projected December 31, 2012 liabilities and 2013 current service costs of the EGD RPP shown in this report of using a discount rate which is 1.00% lower than that used in the projection:

| Scenario | Projection Basis | Reduce Discount Rate by 1% |
|---|---|---|
| Going-concern liabilities | $728.7 | $830.7 |
| Solvency liabilities | $853.4 | $972.9 |
| DB current service cost | $17.7 | $21.1 |

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## Projected Hypothetical Wind-up Balance Sheet at December 31, 2012

The table below details the hypothetical wind-up financial position of the EGD RPP as at December 31, 2011, as well as the projected position as at December 31, 2012.

| Hypothetical Wind-up Financial Position ($Millions) | 12.31.2011 (Actual) | 12.31.2012 (Projected) |
|---|---|---|
| Assets | $715.0 | $758.0 |
| Liabilities | $937.9 | $955.4 |
| Wind-up excess (deficiency) | ($222.9) | ($197.4) |

The assumptions and methodology used to determine the projected hypothetical wind-up balance sheet as at December 31, 2012 are described in Appendix D.

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# APPENDIX C

## Plan Assets

The DB assets of the EGD RPP and the invested assets of the SERP and SSERP are held in trust by CIBC Mellon. SERP and SSERP assets also include the refundable tax account held with CRA. We have relied upon the audited fund statements provided by PriceWaterhouseCoopers LLP as at December 31, 2011.

The starting point for our projections is the market value of each plan's assets as at December 31, 2011.

### Investment Policy

The plans' administrator adopted a statement of investment policy and procedures, last revised in 2011. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the plans' investment objectives. A significant component of this investment policy is the asset mix.

The target asset mix as at March 31, 2012 for the EGD RPP is provided for information purposes:

| | Investment Policy – EGD RPP | | |
|---|---|---|---|
| | **Minimum** | **Target** | **Maximum** |
| Canadian equities | 18% | 21.0% | 24% |
| Global equities | 14% | 17.0% | 21% |
| Emerging market equities | 3% | 6.5% | 10% |
| Fixed income – universe | 24% | 30.0% | 36% |
| Fixed income – real return | 7% | 10.0% | 13% |
| Infrastructure | 5% | 9.0% | 13% |
| Real estate | 3% | 6.5% | 10% |
| Cash and cash equivalents | 0% | 0.0% | 3% |
| | | 100% | |

Because of the mismatch between the EGD RPP assets (which are invested in accordance with the above investment policy) and the liabilities (which tend to behave like long bonds) the financial position of the EGD RPP will fluctuate over time. These fluctuations could be significant and could cause the EGD RPP to become under, or over, funded.

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# APPENDIX D

## Actuarial Methods and Assumptions

### Actuarial Methods – Projected Going-concern Basis

#### *Valuation of Assets*

For purposes of these estimates, we have projected the market value of EGD RPP DB assets at December 31, 2011 using benchmark asset returns (net of all expenses) of 3.88% from January 1, 2012 to March 31, 2012, and our best estimate of asset returns (net of all expenses) of 4.78% from April 1, 2012 to December 31, 2012. Therefore, the annual rate of return over 2012 for the EGD RPP (net of all expenses) assumed in our projection is 8.66%. The assumed annual rate of return over 2012 in respect of the SERP and SSERP was one half of this amount, or 4.33%.

Asset returns after December 31, 2012 are assumed to be 6.37% per year for the EGD RPP, and 3.63% per year for the SERP and SSERP. These assumptions were provided to us by Management.

Estimated future cash flows have been incorporated into our projections.

**Actual assets over year-end 2012 through 2016 will differ from these estimates.**

#### *Valuation of Actuarial Liabilities and Current Service Cost*

For purposes of these estimates, we have continued to use the projected unit credit actuarial cost method for the valuation of actuarial liabilities and current service cost of the plans. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings.

There is no current service cost in respect of the SERP or SSERP.

### Actuarial Assumptions – Projected Going-Concern Basis

The present value of future benefit payment cash flows at each projected year-end is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

For purposes of this projection, we have used the same going-concern valuation assumptions as were used for the December 31, 2011 valuation of the plans, summarized on the following page.

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| Assumption | Current Valuation |
|---|---|
| Discount rate – EGD RPP: | 5.75% |
| Discount rate – SERP/SSERP: | 3.63% |
| Inflation: | 2.25% |
| ITA limit / YMPE Increases: | 2.75% |
| Pensionable Earnings Increases: | 3.50% |
| Post retirement Pension Increases: | 1.125% |
| Retirement Rates: | Age related table |
| Termination Rates: | Age related table |
| Mortality Rates: | 100% of the rates of the 1994 Uninsured Pensioner Mortality Table |
| Mortality Improvements: | Fully generational using Scale AA |
| Disability Rates: | None |
| Eligible Spouse at Retirement: | 80% |
| Spousal Age Difference: | Male two years older |
| DB/DC Choice (EGD RPP only): | Continue in current component |
| Benefits Subject to Consent: | Consent on early retirement |

The assumptions are best-estimate with the exception that the EGD RPP discount rate includes a margin for adverse deviations, as shown below.

**Our assumptions are based on the economic environment as of March 31, 2012 and input provided by the Company for the December 31, 2011 valuation. Assumptions as at year-end 2012 through 2016 will reflect the economic environment and input from the Company at those times, and may differ from those used in these projections.**

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Sample rates from the age related tables are summarized below:

| Age | Termination - Male | Termination - Female | Retirement |
|---|---|---|---|
| 20 | 5.0% | 9.5% | 0.0% |
| 25 | 5.0% | 13.0% | 0.0% |
| 30 | 5.0% | 11.0% | 0.0% |
| 35 | 4.6% | 8.5% | 0.0% |
| 40 | 3.0% | 4.0% | 0.0% |
| 45 | 2.5% | 3.9% | 0.0% |
| 50 | 1.5% | 2.8% | 0.0% |
| 55 | 0.0% | 0.0% | 5.0% |
| 56 | 0.0% | 0.0% | 5.0% |
| 57 | 0.0% | 0.0% | 7.5% |
| 58 | 0.0% | 0.0% | 7.5% |
| 59 | 0.0% | 0.0% | 10.0% |
| 60 | 0.0% | 0.0% | 20.0% |
| 61 | 0.0% | 0.0% | 20.0% |
| 62 | 0.0% | 0.0% | 20.0% |
| 63 | 0.0% | 0.0% | 20.0% |
| 64 | 0.0% | 0.0% | 20.0% |
| 65 | 0.0% | 0.0% | 100.0% |

A 20% retirement rate is assumed in lieu of the above rate in the year in which a member qualifies for early retirement with an unreduced pension and in each subsequent year until age 65.

For members who terminate from the EGD RPP before being eligible to retire we have assumed two-thirds will elect a commuted value determined on a basis consistent with the 2009 CIA Standard, and that one-third will elect a deferred, with pension commencement at age 55.

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The following is a summary of the rationale for the material assumptions that are expected to be used as at December 31, 2012.

## Discount Rate – EGD RPP

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Additional returns assumed to be achievable due to active equity management equal to the fees related to active equity management. Such fees were determined by the difference between the provision for total investment expenses and the hypothetical fees that would be incurred for passive management of all assets.
- Implicit provision for investment and non-investment administrative expenses determined as the expected rate of investment and administrative expenses to be paid from the fund in the future. While recent experience has differed from the assumption, our discussions with management have led us to conclude that this assumption is appropriate.
- A margin for adverse deviations of 0.62%.

The discount rate was developed as follows:

| | |
|---|---|
| Assumed investment return | 6.64% |
| Additional returns for active management[3] | 0.23% |
| Investment management and administrative expense provision | (0.50%) |
| Margin for adverse deviation | (0.62%) |
| Net discount rate | 5.75% |

## Discount Rate – SERP/SSERP

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund documented in the Company's Funding Policy. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

This is based on an assumed inflation rate of 2.25% per year plus a real net rate of return of 5.00% per year which is based on management's best estimate of future returns in accordance with the Company's Funding Policy. This rate reflects the fact that investment income is subject to a 50% refundable tax.

[3] Limited to the incremental cost of fees on an actively managed investment fund relative to a passively managed fund.

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## Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%, and market expectations of long-term inflation implied by the yields on nominal and real return bonds at March 31, 2012 of 2.3%.

## Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

## Pensionable Earnings

This assumption is based on Company expectations.

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## Actuarial Methods and Assumptions – Projected Solvency and Hypothetical Wind-up Bases

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the wind-up is assumed to occur in circumstances that maximize the actuarial liability.

Cash funding costs of the SERP and SSERP have not historically been impacted by the solvency or hypothetical wind-up financial positions, so they have been excluded from this analysis for simplicity.

To determine the actuarial liability of the EGD RPP on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the EGD RPP been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the EGD RPP wind-up is assumed to have taken place are as follows:

- Membership in the EGD RPP ceases on the valuation date; and
- No projection of salaries and YMPE are assumed to occur after the valuation date for active and suspended members.

Thereby giving rise to the following benefits:

- Active and suspended members not within 10 years of pensionable age (under the age of 55) receive the termination benefit under the EGD RPP;
- Active and suspended members within 10 years of pensionable age (age 55 and older) receive the retirement benefit under the EGD RPP; and
- Deferred pensioners, pensioners and survivors receive the benefit to which they are entitled on the valuation date.

It is assumed that, on wind-up, the Company would grant consent to early retirement for all active members.

No benefits payable on wind-up were excluded from our calculations.

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Upon wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for March 31, 2012. Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities. However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. Therefore, we have relied upon the *Canadian Institute of Actuaries Educational Note Supplement: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2011 and December 30, 2012*, reflecting additional supplemental information to March 31, 2012.

In determining the financial position of the Plan on the solvency basis, we have valued those benefits that would have been paid had the EGD RPP been wound-up on the valuation date, with the exception of certain benefits which may be excluded, as permitted by the Ontario *Pension Benefits Act*. Specifically, future cost-of-living increases on pensions in payment were excluded from our calculation of solvency liabilities. All members are assumed to be fully vested in their accrued benefits.

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions below are based on economic conditions as at March 31, 2012.

| **Basis for Benefits Assumed to be Settled Through a Lump Sum** | |
|---|---|
| Non-indexed interest rate: | 2.50% per year for 10 years, 4.00% per year thereafter |
| Partially-indexed (50%) interest rate: | 1.80% per year for 10 years, 2.70% per year thereafter |
| Partially-indexed (55%) interest rate: | 1.80% per year for 10 years, 2.60% per year thereafter |
| **Basis for Benefits Assumed to be Settled Through the Purchase of an Annuity** | |
| Non-indexed interest rate: | 3.45% per year |
| Partially-indexed (50%) interest rate: | 1.93% per year |
| Partially-indexed (55%) interest rate: | 1.78% per year |
| Termination expenses: | $600,000 |

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## *Termination Expenses*

To determine the hypothetical wind-up and solvency position of the EGD RPP, a provision has been made for estimated termination expenses payable from the plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the plan and to be charged to the plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the EGD RPP's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the EGD RPP's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the EGD RPP.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

## *Incremental Cost*

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the EGD RPP at the next valuation date, we must make assumptions about how the EGD RPP membership will evolve over the period until the next valuation.

We have assumed that membership will evolve in a manner consistent with the going-concern assumptions as follows:

- Pensionable earnings, the *Income Tax Act* pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going-concern assumptions;
- Active members accrue pensionable service in accordance with the terms of the EGD RPP; and
- Cost of living adjustments are consistent with the inflation assumption used for the going-concern valuation.

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# APPENDIX E

## Membership Data

### Analysis of Membership Data at December 31, 2011

For purposes of these estimates, we have based our projections on membership data as at December 31, 2011 for each plan, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix D.

Membership data for the EGD RPP as at December 31, 2011 are summarized below.

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| | 12.31.2011 (EGD RPP) |
|---|---|
| **Active Members Accruing Defined Benefit Service (Non-SMEs)** | |
| Number | 1,872 |
| Total base earnings at the valuation date | $141,763,000 |
| Average base earnings at the valuation date | $75,700 |
| Average years of Non-SME DB pensionable service | 12.4 years |
| Average age | 45.4 years |
| **Active Members Accruing Defined Benefit Service (SMEs)** | |
| Number | 33 |
| Total base earnings at the valuation date | $6,836,000 |
| Average base earnings at the valuation date | $207,200 |
| Average years of SME DB pensionable service | 3.4 years |
| Average age | 50.7 years |
| **Suspended Defined Benefit Members Accruing Defined Contribution Service** | |
| Number | 73 |
| Total base earnings at the valuation date | $6,314,000 |
| Average base earnings at the valuation date | $86,500 |
| Average years of Non-SME DB pensionable service | 5.6 years |
| Average age | 46.0 years |
| **Other Suspended Defined Benefit Members (Non-SMEs)** | |
| Number | 18 |
| Total base earnings at the valuation date | $1,962,000 |
| Average base earnings at the valuation date | $109,000 |
| Average years of Non-SME DB pensionable service | 4.3 years |
| Average age | 40.6 years |
| **Other Suspended Defined Benefit Members (SMEs)** | |
| Number | 16 |
| Total base earnings at the valuation date | $4,234,000 |
| Average base earnings at the valuation date | $264,600 |
| Average years of Non-SME DB pensionable service | 7.2 years |
| Average years of SME DB pensionable service | 1.8 years |
| Average age | 44.3 years |

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| | 12.31.2011 (EGD RPP) |
|---|---|
| **Active Defined Contribution Members without Defined Benefit Service** | |
| Number | 197 |
| Total base earnings at the valuation date | $16,347,000 |
| Average base earnings at the valuation date | $83,000 |
| Average age | 41.4 years |
| **Suspended Defined Contribution Members without Defined Benefit Service** | |
| Number | 5 |
| Total base earnings at the valuation date | $667,000 |
| Average base earnings at the valuation date | $133,000 |
| Average age | 36.5 years |
| **Deferred Pensioners** | |
| Number | 191 |
| Total annual pension | $936,000 |
| Average annual pension | $4,900 |
| Average age | 48.5 years |
| **Pensioners and Survivors** | |
| Number | 1,458 |
| Total annual lifetime pension | $29,650,000 |
| Average annual lifetime pension | $20,300 |
| Total annual temporary pension | $1,878,000 |
| Average annual temporary pension | $7,000 |
| Average age | 71.9 years |

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# APPENDIX F

## Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the plans in effect on March 31, 2012. The plans have not been amended since December 31, 2011.

### EGD RPP - DB Component

The following is a summary of the main provisions of the DB component of the EGD RPP in effect on March 31, 2012. This summary is not intended as a complete description of the EGD RPP.

| | |
|---|---|
| **Background** | The EGD RPP became effective January 1, 1971.<br>Benefits are based on a set formula and are entirely paid for by Enbridge.<br>Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service.<br>In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan. |
| **Eligibility for Membership** | New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component. |
| **Vesting** | All employees are immediately vested as of July 1, 2011. |
| **Employee Contributions** | No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required. |
| **Retirement Dates** | Normal Retirement Date<br>• The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday.<br>Early Retirement Date<br>• A member becomes immediately vested and may choose to retire as early as age 55. |

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| | |
|---|---|
| **Normal Retirement Pension** | **Contributory Service:**<br>2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service;<br>less<br>100% of the Contributory Canada Pension Plan Entitlement.<br>**Non-Contributory Service:**<br>1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service;<br>less<br>50% of the Non-Contributory Canada Pension Plan Entitlement;<br>**SME Credited Service:**<br>2.0% of Final Three Year Average Earnings multiplied by years of SME credited service. |
| **Final Five Year Average Earnings** | Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees. |
| **Final Three Year Average Earnings** | Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by 3. |
| **Canada Pension Plan Entitlement** | **Contributory Service:**<br>One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years.<br>**Non-Contributory Service:**<br>Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing a dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%. |

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| | |
|---|---|
| **Early Retirement Pension** | The following benefits apply if a member retires early with the Company's consent:<br>• If the member has attained age 60, the pension payable is as described above in the Normal Retirement section.<br>• If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement.<br>• If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement.<br>• If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions.<br>If a member retires without company consent the benefit is actuarially equivalent to the benefit payable at age 65. |
| **Maximum Pension** | The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of:<br>• 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and<br>• $2,646.67, or such other maximum as may apply from time to time<br>indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the *Income Tax Act* rules. |
| **Indexation of Pensions in Payment** | On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership.<br>Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis. |

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| | |
|---|---|
| **Death Benefits** | **Death Before Eligible for Early Retirement**<br>If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service.<br>**Death After Eligibility for Early Retirement**<br>If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service.<br>**Death After Retirement**<br>The death benefit payable is in accordance with the form elected.<br>The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members. |
| **Termination Benefits** | If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP. |
| **Disability Benefits** | Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled. |

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## EGD RPP - DC Component

The following is a summary of the main provisions of the DC component of the EGD RPP in effect on March 31, 2012. This summary is not intended as a complete description of the EGD RPP.

| | |
|---|---|
| **Background** | The DC component of the EGD RPP became effective July 1, 2001.<br>Employer contributions are remitted to individual member accounts and are credited with interest.<br>Members receive the balance of their individual employer account upon termination, death or retirement. |
| **Eligibility for Membership** | New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component. |
| **Vesting** | All employees are immediately vested as of July 1, 2011. |
| **Employee Contributions** | No employee contributions are required or permitted. |
| **Employer Contributions** | Employer contributions to the DC component are based on a member's points.<br>• less than 40 points: 4.0% of pensionable earnings[4]<br>• 40 to 60 points: 5.5% of pensionable earnings<br>• greater than 60 points: 7.0% of pensionable earnings |
| **Maximum Contribution** | The employer contributions are limited to the amounts under the ITA. |
| **Pensionable Earnings** | Base salary plus 50% of actual bonus received. |

[4] For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

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## SERP / SSERP

The following is a summary of the main provisions of the SERP and SSERP in effect on March 31, 2012. This summary is not intended as a complete description of the SERP or SSERP.

| | |
|---|---|
| **Background - SERP** | The SERP became effective November 19, 1987. It provides to designated employees benefit amounts that would otherwise be payable under the EGD RPP beyond the ITA maximum pension limit on service accrued prior to January 1, 2000.<br>The SERP is closed to new entrants. |
| **Background - SSERP** | The SSERP became effective November 19, 1984. Only members designated by Enbridge Gas Distribution Inc. were able to join the SSERP.<br>The SSERP is closed to new entrants, and the only remaining members are pensioners and survivors. |

MERCER

Mercer (Canada) Limited
222 - 3rd Avenue SW Suite 1200 Calgary,
Alberta T2P 0B4
+1 403 269 4945



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# DRIVERS OF DEFICIENCY / (SUFFICIENCY)

1. The numeric information filed in Appendix A of this exhibit identifies specific elements or "drivers" that have contributed to the revenue deficiency of $91.3 million for the 2013 Test Year.

2. While in cost of service, a typical drivers of deficiency/(sufficiency) analysis for a particular fiscal or test year is achieved by comparing all forecast elements of revenues and costs contained in that year's revenue requirement to the previous fiscal year's Board Approved similar revenues and costs.

3. When exiting an Incentive Regulation ("IR") period, where changes in annual rates or revenues during the IR period are not based on approved forecasts of costs, total forecast costs for the first cost of service year cannot be compared to relevant or similar Board approved costs for the previous fiscal year. That is because the rates established during the IR period are not necessarily underpinned or established/adjusted by cost forecasts.

4. As a result, in a first cost of service test year after an IR period, the calculation of whether there is a deficiency / rate increase, or (sufficiency) / rate decrease, is determined by comparing the forecast revenues for the Test Year based on Board Approved rates from the previous year to forecast revenues for the Test Year based on cost of service rates. That is accomplished through the following process. The final IR year's rates, which for EGD is 2012 rates determined through an IR formula plus some cost of service pass-through Y-factor items, are multiplied by forecast 2013 volumes to arrive at forecast 2013 revenues. Those revenues are then compared to the total forecast revenue requirement or total costs from the cost of

service application, less other non rate specific revenue. This process, which is set out at Appendix B to this exhibit, shows that EGD has a $91.3 million deficiency for 2013.

5. As shown in Appendix B of this exhibit, the total revenue forecast for the 2013 Test Year (using 2012 Board-approved rates) is $2,559.1 million, Column 4, Line 24 while the total revenue requirement forecast (on a cost of service basis) is $2,650.4 million, Column 4, Line 19. This results in the $91.3 million deficiency.

Drivers of the 2013 Deficiency

6. In order to identify what items are contributing to the overall deficiency, it is appropriate to compare previous Board-approved costs to the costs set out in the 2013 cost of service filing. One cannot simply compare 2012 costs to 2013 costs, because there are no Board Approved costs for most 2012 items (with the exception of Y-factor items such as DSM and CIS/Customer Care). Instead, in most instances, one must compare 2007 costs (from EGD's last cost of service case) to 2013 costs. At the same time, one must also take account of the increase in revenue requirement added using the IR formula for the 2008 to 2012 years, so that the ultimate indicated deficiency is reflective of the difference between 2012 and 2013 rates.

7. The results of EGD's analysis of the drivers of deficiency are set out in the chart at Appendix A to this Exhibit.

A. Previous OEB Decision / Report Rate Impacts

8. As shown at Lines 1 to 3 of Appendix A within this exhibit, $31.4 million of the total deficiency is made up of amounts resulting from previous Board Decisions and

Reports. These are items which the Board has already examined and approved, and which EGD is simply implementing in 2013, as part of its cost of service filing. There is no need for these matters to be re-examined in this case. As such, these items must be viewed separately from the remaining Utility related rate impacts.

9. As shown at Line 1, $11 million of the required increase in rates was approved by the Board in relation to Customer Care / CIS costs ("CC/CIS") within EB-2011-0226. The derivation of the $11 million CC/CIS rate increase is shown in Appendix B, Column 3 with an explanation of the required separate treatment of CC/CIS costs filed at Exhibit D1, Tab 12, Schedule 1.

10. As shown at Line 2, $20.4 million of the required increase in rates is the result of the application of the Board's new ROE Formula as determined within the EB-2009-0084 Board Report. The $20.4 million change is the result of updating the previous approved Return On Equity ("ROE") for EGD of 8.39% to a current updated 2013 estimate of 9.42%, an ROE percentage increase of 1.03%. The 1.03% increase in ROE deficiency is applied against a 36% deemed equity level of $1,483.3 million relating to the Utility Rate Base of $4,120.3 exclusive of CIS, shown in Column 2 of Appendix B, which is then divided by the reciprocal of the 2013 income tax rate of 25.5%, resulting in a $20.4 million rate increase (($1,483.3 x 1.03%)=15.2/(1-25.5%)=$20.4).

B. Remaining Utility Related Rate Impacts in Appendix A

11. Lines 4 through 12 within Appendix A show major individual deficiency/(sufficiency) driver amounts for all other Utility related items, totaling $59.9 million, as shown at Line 13.

12. Line 4 shows the amount of incremental revenue added from 2008 to 2012 through the application of the IR formula (totaling $104 million) as an offset versus other elements of costs which have changed relative to 2007 Board Approved levels, but for which there are no specific 2012 Board approved levels of costs. In essence the $104 million is representative of incremental amounts approved to be received in rates during IR but which does not relate to any particular cost categories as of the end of 2012. As explained above, while EGD has been in IR in 2008-2012, the major portion of increases in approved revenues and rates each year have been in relation to the formulaic element of EGD's IR model, and there has been no examination or approval of changes to most of EGD's specific costs.

13. Line 5 shows drivers of deficiency impacts for various elements of O&M. The deficiency of $26 million of pension costs results from comparing the 2013 forecast cost of $27.7 million versus an allocated Board Approved 2007 level of $1.7 million, Exhibit D1, Tab 3, Schedule 1, Table 1, Line 4, Column 1 to Column 4. The deficiency of $12.2 million of RCAM costs results from comparing the 2013 forecast cost of $30.3 million versus an allocated Board Approved level of $18.1 million, Exhibit D1, Tab 3, Schedule 1, Table 1, Line 2, Column 1 to Column 4. The deficiency of $0.5 million of DSM costs results from comparing the 2013 forecast of $28.6 million to the level of costs known to be approved in 2012 rates by the Board of $28.1 million. The comparison here is between 2012 and 2013, because DSM costs have been recovered (and approved annually) as a separate cost of service Y-factor through EGD's 2008 – 2012 IR term. The deficiency of $60.2 million of other O&M results from increases in all remaining O&M categories other than those related to the Customer Care agreement, pension, RCAM, and DSM in relation to previous 2007 Board Approved levels.

14. Line 6 shows a deficiency impact of $102.4 million which is associated with the impact of increased rate base and related changes in depreciation, capital cost allowance tax deductions and debt issuance levels in comparison to previous 2007 Board Approved levels.

15. Line 7 shows a deficiency impact of $22.6 million which is the result of EGD's requested deemed equity level being changed from the current allowed level of 36% to 42% relative to a Utility Rate Base of $4,120.3 exclusive of CIS, shown in Column 2 of Appendix B. Evidence in support of this requested change is found at Exhibit E2, Tab 1, Schedule 2.

16. Line 8 shows a deficiency impact of $4 million associated with increases in municipal taxes as a result of anticipated increased municipal tax rates, an increase in municipal taxes from mains and service growth and increases in current value assessment. This deficiency impact is in comparison to 2007 Board Approved amounts.

17. Line 9 shows a sufficiency impact of $8.5 million associated with increases in other revenues and other tax deductible amounts in comparison to 2007 Board Approved amounts.

18. Line 10 shows a sufficiency impact of $9.7 million which is the result of a variety of impacts on margin, from changes in volumes and mix, changes in sources of gas supply mix and related impacts within gas in storage values and related carrying costs when comparing 2013 forecast volumes to 2012 Board Approved volumes.

19. Line 11 shows a sufficiency impact of $20.1 million which results from reductions to income tax rates and rules to reflect 2013 forecast rates and rules.

Witness: K. Culbert

20. Line 12 shows a sufficiency impact of $25.7 million which is the result of reductions in the 2013 forecast average cost rates for long term debt 5.90%, short term debt 3.70%, and preference shares 4.16% in comparison to 2007 Board Approved cost rates of 6.79%, 4.12% and 5.00% respectively.

21. In total, as set out in Line 14 of Appendix A, the sum of the various drivers of deficiency is $91.3M, which is the same amount indicated at Appendix B.

Appendix A

| Line No. | Drivers of 2013 Deficiency (required rates increase) | Col. 1 Deficiency / (Sufficiency) $(millions) |
|---|---|---|
| | **Previous OEB Decision / Report Rate Impacts:** | |
| 1. | Customer Care / CIS Agreement Approval (EB-2011-0226) | 11.0 |
| 2. | Return on Equity using OEB fair return standard (EB-2009-0084) | 20.4 |
| 3. | Sub-total previous OEB Decision / Report impacts | 31.4 |
| | **Remaining Utility Related Rate Impacts:** | |
| 4. | 2008-2012 Incentive formula revenue, not allocated to specific costs | (104.0) |
| 5. | Operating & Maintenance cost | |
| | -pension | 26.0 |
| | -RCAM | 12.2 |
| | -DSM | 0.5 |
| | -all other (salaries, wages, exp, training business alliance cost) | 60.2 |
| 6. | Rate Base and associated depreciation, CCA, and debt level required adjustments | 102.4 |
| 7. | Deemed Equity level to 42% | 22.6 |
| 8. | Municipal taxes | 4.0 |
| 9. | Other revenues, all other tax adds & deducts | (8.5) |
| 10. | Volumes/supply mix, storage carrying cost changes | (9.7) |
| 11. | Remaining tax rate decrease (re-base) | (20.1) |
| 12. | Financing rates decrease (re-base) | (25.7) |
| 13. | Sub-total Remaining Utility Related Impacts | 59.9 |
| 14. | Total 2013 Deficiency (required rate increase) (line 3 + line 13) | 91.3 |

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APPENDIX B
REVENUE REQUIREMENT
AND SUFFICIENCY
2013 TEST YEAR

| Line No. | | Col. 1 Reference | Col. 2 Exclusive of CC-CIS ($Millions) | Col. 3 CC-CIS ($Millions) | Col. 4 EGD Total ($Millions) |
|---|---|---|---|---|---|
| | **Cost of Capital** | | | | |
| 1. | Rate base | B3.T1.S1.P1 | 4,120.3 | 70.5 | 4,190.8 |
| 2. | Required rate of return | E3.T1.S1.P1 | 7.35% | 6.44% | 7.34% |
| | | | 302.8 | 4.6 | 307.4 |
| | **Cost of Service** | | | | |
| 3. | Gas costs | D3.T1.S1.P1 | 1,548.6 | | 1,548.6 |
| 4. | Operation and maintenance | D3.T1.S1.P2 | 336.7 | 89.4 | 426.1 |
| 5. | Depreciation and amortization | D3.T1.S1.P3 | 289.6 | 12.7 | 302.3 |
| 6. | Fixed financing costs | D3.T1.S1.P4 | 2.3 | - | 2.3 |
| 7. | Debt redemption premium amortization | D3.T1.S1.P5 | - | - | - |
| 8. | Company share of IR agreement tax savings | D3.T1.S1.P6 | - | - | - |
| 9. | Municipal and other taxes | D3.T1.S1.P7 | 40.1 | - | 40.1 |
| | | | 2,217.3 | 102.1 | 2,319.4 |
| | **Miscellaneous operating and non operating revenue** | | | | |
| 10. | Other operating revenue | C3.T1.S1.P1 | (38.3) | - | (38.3) |
| 11. | Interest and property rental | C3.T1.S1.P2 | 0.0 | - | - |
| 12. | Other income | C3.T1.S1.P3 | (0.7) | - | (0.7) |
| | | | (39.0) | - | (39.0) |
| | **Income taxes on earnings** | | | | |
| 13. | Excluding tax shield | D3.T1.S1.P1 | 73.2 | 9.0 | 82.2 |
| 14. | Tax shield provided by interest expense | D3.T1.S1.P2 | (34.6) | (0.9) | (35.5) |
| | | | 38.6 | 8.1 | 46.7 |
| | **Taxes on deficiency** | | | | |
| 15. | Gross deficiency -w/ out CC/ CIS | E3.T1.S1.P1 | (80.3) | - | (80.3) |
| 16. | Net deficiency -w/ out CC/ CIS | E3.T1.S1.P2 | (59.8) | - | (59.8) |
| | | | 20.5 | - | 20.5 |
| 17. | Sub-total Revenue Requirement | | 2,540.2 | 114.8 | 2,655.0 |
| 18. | Customer Care Rate Smoothing Variance Account Adjustment | | - | (4.6) | (4.6) |
| 19. | **Revenue Requirement** | | 2,540.2 | 110.2 | 2,650.4 |
| | **Revenue at existing Rates** | | | | |
| 20. | Gas sales | C3.T1.S1.P1 | 2,137.5 | 80.2 | 2,217.7 |
| 21. | Transportation service | C3.T1.S1.P2 | 320.6 | 19.0 | 339.6 |
| 22. | Transmission, compression and storage | C3.T1.S1.P3 | 1.7 | | 1.7 |
| 23. | Rounding adjustment | | 0.1 | | 0.1 |
| 24. | Total | | 2,459.9 | 99.2 | 2,559.1 |
| 25. | **Gross revenue deficiency** | | (80.3) | (11.0) | (91.3) |

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# ENBRIDGE GAS DISTRIBUTION INC.

## CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

## June 30, 2011

# CONSOLIDATED STATEMENTS OF EARNINGS

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian of dollars)* | | | | |
| Gas commodity and distribution revenue | **373** | 316 | **1,205** | 1,152 |
| Transportation of gas for customers | **71** | 78 | **210** | 219 |
| | **444** | 394 | **1,415** | 1,371 |
| Gas commodity and distribution costs excluding depreciation | **(207)** | (178) | **(853)** | (844) |
| Gas distribution margin | **237** | 216 | **562** | 527 |
| Other revenue | **29** | 29 | **57** | 54 |
| | **266** | 245 | **619** | 581 |
| Expenses | | | | |
| Operating and administrative | **96** | 95 | **188** | 189 |
| Depreciation and amortization | **70** | 66 | **139** | 133 |
| Municipal and other taxes | **11** | 14 | **22** | 26 |
| Earnings sharing | **2** | 8 | **8** | 19 |
| | **179** | 183 | **357** | 367 |
| | **87** | 62 | **262** | 214 |
| Affiliate financing income | **15** | 15 | **31** | 31 |
| Interest expense | **(40)** | (46) | **(86)** | (92) |
| | **62** | 31 | **207** | 153 |
| Income taxes | | | | |
| Current | **(12)** | (3) | **(52)** | (39) |
| Future | **-** | 1 | **4** | 1 |
| | **(12)** | (2) | **(48)** | (38) |
| Earnings | **50** | 29 | **159** | 115 |
| Preferred share dividends | **-** | (1) | **(1)** | (1) |
| Earnings attributable to the common shareholder | **50** | 28 | **158** | 114 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| Earnings | **50** | 29 | **159** | 115 |
| Other comprehensive income/(loss) | | | | |
| Change in fair value of cash flow hedges, net of tax | **-** | (7) | **1** | (9) |
| Reclassification to earnings of realized losses on cash flow hedges, net of tax | **-** | - | **(1)** | (1) |
| Other comprehensive loss | **-** | (7) | **-** | (10) |
| Comprehensive income | **50** | 22 | **159** | 105 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

| Six months ended June 30, | **2011** | 2010 |
|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | |
| Preferred shares | **100** | 100 |
| Common shares | **1,071** | 1,071 |
| Contributed surplus | **202** | 202 |
| Retained earnings | | |
| Balance at beginning of period | **572** | 596 |
| Earnings attributable to the common shareholder | **158** | 114 |
| Common share dividends declared | **(109)** | (108) |
| Balance at end of period | **621** | 602 |
| Accumulated other comprehensive loss | | |
| Balance at beginning of period | **(18)** | (2) |
| Other comprehensive loss | **-** | (10) |
| Balance at end of period | **(18)** | (12) |
| Total shareholders' equity | **1,976** | 1,963 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| **Operating activities** | | | | |
| Earnings | **50** | 29 | **159** | 115 |
| Depreciation and amortization | **70** | 66 | **139** | 133 |
| Future income taxes | **-** | (1) | **(4)** | (1) |
| Other | **(1)** | 5 | **1** | 2 |
| Changes in operating assets and liabilities | **(15)** | 159 | **257** | 404 |
| | **104** | 258 | **552** | 653 |
| **Investing activities** | | | | |
| Additions to property, plant and equipment | **(97)** | (71) | **(154)** | (124) |
| Additions to intangible assets | **(5)** | (5) | **(12)** | (11) |
| Change in construction payable | **8** | 5 | **(11)** | (14) |
| Other | **-** | 3 | **2** | 1 |
| | **(94)** | (68) | **(175)** | (148) |
| **Financing activities** | | | | |
| Net change in short-term borrowings | **137** | (89) | **(88)** | (355) |
| Repayment of short-term note payable to affiliate company | **(1)** | (2) | **(3)** | (2) |
| Debenture and term note repayments | **(150)** | - | **(150)** | - |
| Preferred share dividends | **-** | - | **(1)** | (1) |
| Common share dividends | **(55)** | (54) | **(109)** | (101) |
| Other | **1** | - | **-** | - |
| | **(68)** | (145) | **(351)** | (459) |
| Increase/(decrease) in cash and cash equivalents | **(58)** | 45 | **26** | 46 |
| Cash and cash equivalents/(bank overdraft) at beginning of period | **66** | (12) | **(18)** | (13) |
| **Cash and cash equivalents at end of period** | **8** | 33 | **8** | 33 |
| | | | | |
| Cash and cash equivalents[1] | **8** | 33 | **8** | 33 |
| Bank overdraft | **-** | - | **-** | - |
| | **8** | 33 | **8** | 33 |
| | | | | |
| **Supplementary cash flow information** | | | | |
| Income taxes paid | **16** | 15 | **35** | 30 |
| Interest paid | **60** | 62 | **90** | 92 |

*See accompanying notes to the unaudited consolidated financial statements.*

[1] *Cash and cash equivalents consists of $8 million (2010 - $23 million) of cash and $nil (2010 - $10 million) of short-term investments.*

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| | **June 30, 2011** | December 31, 2010 |
|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | |
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | **8** | - |
| Accounts receivable and other | **451** | 802 |
| Gas inventories | **350** | 400 |
| | **809** | 1,202 |
| Property, plant and equipment, net | **4,520** | 4,458 |
| Investment in affiliate company | **825** | 825 |
| Deferred amounts and other assets | **478** | 487 |
| Intangible assets | **164** | 167 |
| | **6,796** | 7,139 |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | | |
| Bank overdraft | **-** | 18 |
| Short-term borrowings | **241** | 332 |
| Accounts payable and other | **682** | 836 |
| Current maturities of long-term debt | **-** | 150 |
| Future income taxes | **1** | 5 |
| | **924** | 1,341 |
| Long-term debt | **2,268** | 2,267 |
| Other long-term liabilities | **1,086** | 1,058 |
| Future income taxes | **167** | 171 |
| Loans from affiliate company | **375** | 375 |
| | **4,820** | 5,212 |
| Shareholders' equity | | |
| Share capital | | |
| Preferred shares | **100** | 100 |
| Common shares | **1,071** | 1,071 |
| Contributed surplus | **202** | 202 |
| Retained earnings | **621** | 572 |
| Accumulated other comprehensive loss | **(18)** | (18) |
| | **1,976** | 1,927 |
| Contingencies *(Note 3)* | | |
| | **6,796** | 7,139 |

*See accompanying notes to the unaudited consolidated financial statements.*

# NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements of Enbridge Gas Distribution Inc. (the Company) have been prepared in accordance with Part V - Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook (Part V). These interim consolidated financial statements do not include all disclosures required for annual financial statements and therefore should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's 2010 Annual Report. Amounts are stated in Canadian dollars unless otherwise noted. These interim consolidated financial statements follow the same significant accounting policies and methods of application as those included in the 2010 Annual Report, except as described in Note 1.

Earnings for interim periods may not be indicative of results for the fiscal year due to the seasonal nature of the business.

Certain comparative amounts have been reclassified to conform to the current period's presentation.

## 1. CHANGES IN ACCOUNTING POLICIES

**Business Combinations**
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings or cash flows for the three or six month period ended June 30, 2011.

**Consolidated Financial Statements and Noncontrolling Interests**
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and non-controlling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings or cash flows for the current or prior periods presented.

## 2. POST-EMPLOYMENT BENEFITS

The Company has two registered pension plans which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees. In addition, the Company has two supplemental non-contributory defined benefit pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides post-employment benefits other than pensions (OPEB) for qualifying retired employees.

Costs related to the period on an accrual basis are presented below and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense is comprised of plan contributions and actual OPEB benefit costs paid, which is consistent with the recovery of such costs in rates. Such costs totaled $2 million and $4 million for the three and six months ended June 30, 2011, respectively (2010 - $2 million and $4 million, respectively).

**Net Pension Plan and OPEB Costs on an Accrual Basis**

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| Benefits earned during the period | **5** | 3 | **9** | 7 |
| Interest cost on projected benefit obligations | **11** | 11 | **22** | 21 |
| Expected return on plan assets | **(13)** | (12) | **(26)** | (24) |
| Amortization of unrecognized amounts | **(2)** | (2) | **(3)** | (4) |
| Pension and OPEB Costs | **1** | - | **2** | - |

## 3. CONTINGENCIES

**Bloor Street Incident**

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Superior Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. The new trial is scheduled to commence in November 2011. Management does not believe any fines that may be levied will have a material financial impact on the Company.

**Other Litigation**

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

# ENBRIDGE INC.

# CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

## June 30, 2011

# CONSOLIDATED STATEMENTS OF EARNINGS

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars, except per share amounts)* | | | | |
| Revenues | | | | |
| Commodity sales | **4,095** | 2,725 | **7,943** | 5,985 |
| Transportation and other services | **886** | 780 | **1,751** | 1,497 |
| | **4,981** | 3,505 | **9,694** | 7,482 |
| Expenses | | | | |
| Commodity costs | **3,914** | 2,556 | **7,514** | 5,625 |
| Operating and administrative | **378** | 359 | **724** | 683 |
| Depreciation and amortization | **226** | 198 | **456** | 398 |
| | **4,518** | 3,113 | **8,694** | 6,706 |
| | **463** | 392 | **1,000** | 776 |
| Income from equity investments | **80** | 71 | **159** | 157 |
| Other income/(expense) | **36** | (87) | **114** | 52 |
| Interest expense | **(185)** | (173) | **(362)** | (323) |
| | **394** | 203 | **911** | 662 |
| Income taxes | **(122)** | (49) | **(236)** | (152) |
| Earnings | **272** | 154 | **675** | 510 |
| Less: Earnings attributable to noncontrolling interests | **(11)** | (14) | **(19)** | (26) |
| Earnings attributable to Enbridge Inc. | **261** | 140 | **656** | 484 |
| Preferred share dividends | **(2)** | (2) | **(4)** | (4) |
| Earnings attributable to Enbridge Inc. common shareholders | **259** | 138 | **652** | 480 |
| Earnings per common share attributable to Enbridge Inc. common shareholders | **0.35** | 0.19 | **0.87** | 0.65 |
| Diluted earnings per common share attributable to Enbridge Inc. common shareholders | **0.34** | 0.18 | **0.86** | 0.64 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| Earnings | **272** | 154 | **675** | 510 |
| Other comprehensive income/(loss) | | | | |
| Change in unrealized gain/(loss) on cash flow hedges, net of tax | **(20)** | (70) | **54** | (112) |
| Change in unrealized gain/(loss) on net investment hedges, net of tax | **11** | (51) | **41** | (32) |
| Reclassification to earnings of realized cash flow hedges, net of tax | **5** | 9 | **(10)** | 31 |
| Other comprehensive loss from equity investees, net of tax | **(1)** | (15) | **(13)** | (13) |
| Change in foreign currency translation adjustment | **(37)** | 234 | **(169)** | 78 |
| Other comprehensive income/(loss) | **(42)** | 107 | **(97)** | (48) |
| Comprehensive income | **230** | 261 | **578** | 462 |
| Less: Comprehensive income attributable to noncontrolling interests | **(9)** | (22) | **(1)** | (21) |
| Comprehensive income attributable to Enbridge Inc. | **221** | 239 | **577** | 441 |
| Preferred share dividends | **(2)** | (2) | **(4)** | (4) |
| Comprehensive income attributable to Enbridge Inc. common shareholders | **219** | 237 | **573** | 437 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

| | Six months ended June 30, | |
|---|---|---|
| | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars, except per share amounts)* | | |
| Preferred shares | **125** | 125 |
| Common shares | | |
| Balance at beginning of period | **3,683** | 3,379 |
| Dividend reinvestment and share purchase plan | **118** | 113 |
| Shares issued on exercise of stock options | **26** | 30 |
| Balance at end of period | **3,827** | 3,522 |
| Contributed surplus | | |
| Balance at beginning of period | **59** | 54 |
| Stock-based compensation | **12** | 8 |
| Options exercised | **(3)** | (3) |
| Other | **(3)** | - |
| Balance at end of period | **65** | 59 |
| Retained earnings | | |
| Balance at beginning of period | **4,734** | 4,400 |
| Earnings attributable to Enbridge Inc. common shareholders | **652** | 480 |
| Common share dividends declared | **(378)** | (322) |
| Dividends paid to reciprocal shareholder | **12** | 9 |
| Balance at end of period | **5,020** | 4,567 |
| Accumulated other comprehensive loss | | |
| Balance at beginning of period | **(882)** | (543) |
| Other comprehensive loss | **(79)** | (43) |
| Balance at end of period | **(961)** | (586) |
| Reciprocal shareholding | **(187)** | (154) |
| Total Enbridge Inc. shareholders' equity | **7,889** | 7,533 |
| Noncontrolling interests | | |
| Balance at beginning of period | **658** | 727 |
| Earnings attributable to noncontrolling interests | **19** | 26 |
| Other comprehensive loss attributable to noncontrolling interests | | |
| Change in unrealized loss on cash flow hedges, net of tax | **(3)** | (7) |
| Other comprehensive loss from equity investees, net of tax | **(4)** | (4) |
| Change in foreign currency translation adjustment | **(11)** | 6 |
| | **(18)** | (5) |
| Comprehensive income attributable to noncontrolling interests | **1** | 21 |
| Distributions, net | **(4)** | (23) |
| Acquisition (*Note 4*) | **(27)** | - |
| Other | **1** | 14 |
| Balance at end of period | **629** | 739 |
| Total shareholders' equity | **8,518** | 8,272 |
| | | |
| Dividends paid per common share | **0.490** | 0.425 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| **Operating activities** | | | | |
| Earnings attributable to Enbridge Inc. | **261** | 140 | **656** | 484 |
| Depreciation and amortization | **226** | 198 | **456** | 398 |
| Unrealized losses on derivative instruments | **45** | 99 | **8** | 83 |
| Allowance for equity funds used during construction | **(1)** | (26) | **(2)** | (78) |
| Cash distributions in excess of/(less than) equity earnings | **1** | (21) | **(5)** | (57) |
| Gain on reduction of ownership interest | **-** | (2) | **-** | (2) |
| Future income taxes | **53** | 28 | **143** | 113 |
| Noncontrolling interests | **11** | 14 | **19** | 26 |
| Changes in regulatory assets and liabilities | **27** | (6) | **56** | 29 |
| Other | **11** | 31 | **(1)** | 20 |
| Changes in operating assets and liabilities | **(59)** | 56 | **202** | 141 |
| | **575** | 511 | **1,532** | 1,157 |
| **Investing activities** | | | | |
| Acquisition (*Note 4*) | **(28)** | (52) | **(28)** | (52) |
| Additions to property, plant and equipment | **(406)** | (490) | **(813)** | (865) |
| Additions to intangible assets | **(10)** | (8) | **(19)** | (17) |
| Change in construction payable | **(19)** | 7 | **(59)** | (86) |
| Long-term investments (*Note 4*) | **(161)** | (7) | **(167)** | (93) |
| Affiliate loans, net | **2** | (8) | **(1)** | (74) |
| | **(622)** | (558) | **(1,087)** | (1,187) |
| **Financing activities** | | | | |
| Net change in short-term borrowings | **137** | (90) | **(88)** | (356) |
| Net change in commercial paper and credit facility draws | **206** | (437) | **179** | (93) |
| Debenture and term note issues | **-** | 750 | **-** | 1,250 |
| Debenture and term note repayments | **(150)** | (54) | **(150)** | (504) |
| Net change in Southern Lights project financing | **(16)** | - | **(40)** | 51 |
| Non-recourse debt issues | **-** | 1 | **9** | 6 |
| Non-recourse debt repayments | **(41)** | (35) | **(42)** | (35) |
| Distributions to noncontrolling interests, net | **(4)** | (16) | **(4)** | (23) |
| Common shares issued | **6** | 10 | **22** | 24 |
| Preferred share dividends | **(2)** | (2) | **(4)** | (4) |
| Common share dividends | **(136)** | (104) | **(260)** | (209) |
| | **-** | 23 | **(378)** | 107 |
| Effect of translation of foreign denominated cash and cash equivalents | **(1)** | 12 | **(6)** | 5 |
| Increase/(decrease) in cash and cash equivalents | **(48)** | (12) | **61** | 82 |
| Cash and cash equivalents at beginning of period | **351** | 421 | **242** | 327 |
| Cash and cash equivalents at end of period[1] | **303** | 409 | **303** | 409 |
| **Supplementary cash flow information** | | | | |
| Income taxes paid/(received) | **(64)** | 38 | **(19)** | 104 |
| Interest paid | **222** | 192 | **378** | 341 |

*See accompanying notes to the unaudited consolidated financial statements.*

1 *Cash and cash equivalents consists of $187 million (2010 - $211 million) of cash and $116 million (2010 - $198 million) of short-term investments and includes restricted cash of $12 million (2010 - $6 million), and joint venture cash which is not readily accessible by the Company of $62 million (2010 - $78 million).*

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| | **June 30, 2011** | December 31, 2010 |
|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | |
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | **303** | 242 |
| Accounts receivable and other | **2,334** | 2,706 |
| Inventory | **672** | 813 |
| | **3,309** | 3,761 |
| Property, plant and equipment, net | **20,609** | 20,332 |
| Long-term investments | **2,275** | 2,198 |
| Deferred amounts and other assets | **3,035** | 2,886 |
| Intangible assets | **454** | 478 |
| Goodwill | **383** | 385 |
| Future income taxes | **58** | 80 |
| | **30,123** | 30,120 |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | | |
| Short-term borrowings | **238** | 326 |
| Accounts payable and other | **2,339** | 2,688 |
| Interest payable | **113** | 117 |
| Current maturities of long-term debt | **3** | 154 |
| Current maturities of non-recourse long-term debt | **71** | 70 |
| | **2,764** | 3,355 |
| Long-term debt | **13,624** | 13,561 |
| Non-recourse long-term debt | **1,014** | 1,061 |
| Other long-term liabilities | **1,630** | 1,473 |
| Future income taxes | **2,573** | 2,447 |
| | **21,605** | 21,897 |
| Shareholders' equity | | |
| Share capital | | |
| Preferred shares | **125** | 125 |
| Common shares | **3,827** | 3,683 |
| Contributed surplus | **65** | 59 |
| Retained earnings | **5,020** | 4,734 |
| Accumulated other comprehensive loss | **(961)** | (882) |
| Reciprocal shareholding | **(187)** | (154) |
| Total Enbridge Inc. shareholders' equity | **7,889** | 7,565 |
| Noncontrolling interests | **629** | 658 |
| | **8,518** | 8,223 |
| Commitments and contingencies *(Note 8)* | | |
| | **30,123** | 30,120 |

*See accompanying notes to the unaudited consolidated financial statements.*

# NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with Part V - Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These interim consolidated financial statements do not include all disclosures required for annual financial statements and therefore should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's 2010 Annual Report. These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 10. Amounts are stated in Canadian dollars unless otherwise noted. These interim consolidated financial statements follow the same significant accounting policies and methods of application as those included in the 2010 Annual Report, except as described in Note 1.

Earnings for interim periods may not be indicative of results for the fiscal year due to the seasonal nature of the gas distribution utility business and other factors.

Certain comparative amounts have been reclassified to conform to the current period's presentation.

## 1. CHANGES IN ACCOUNTING POLICIES

**Business Combinations**
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard had no material impact to the Company's earnings or cash flows for the three or six month period ended June 30, 2011.

**Consolidated Financial Statements and Noncontrolling Interests**
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements,* and 1602, *Noncontrolling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only there has been no impact to the Company's earnings or cash flows for the current or prior periods presented.

# 2. SEGMENTED INFORMATION

| **Three months ended June 30, 2011** | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | | |
| Revenues | **519** | **501** | **3,875** | **86** | **-** | **4,981** |
| Commodity costs | **-** | **(210)** | **(3,704)** | **-** | **-** | **(3,914)** |
| Operating and administrative | **(165)** | **(115)** | **(61)** | **(30)** | **(7)** | **(378)** |
| Depreciation and amortization | **(78)** | **(79)** | **(42)** | **(24)** | **(3)** | **(226)** |
| | **276** | **97** | **68** | **32** | **(10)** | **463** |
| Income/(loss) from equity investments | **-** | **-** | **-** | **81** | **(1)** | **80** |
| Other income/(expense) | **71** | **(3)** | **9** | **17** | **(58)** | **36** |
| Interest expense | **(65)** | **(41)** | **(24)** | **(17)** | **(38)** | **(185)** |
| Income taxes | **(84)** | **(12)** | **(19)** | **(40)** | **33** | **(122)** |
| Earnings | **198** | **41** | **34** | **73** | **(74)** | **272** |
| Noncontrolling interests | **(1)** | **-** | **-** | **(10)** | **-** | **(11)** |
| Preferred share dividends | **-** | **-** | **-** | **-** | **(2)** | **(2)** |
| Earnings attributable to Enbridge Inc. common shareholders | **197** | **41** | **34** | **63** | **(76)** | **259** |
| Additions to property, plant and equipment [1] | **180** | **101** | **118** | **5** | **3** | **407** |
| Total assets | **11,903** | **7,014** | **5,550** | **3,772** | **1,884** | **30,123** |

| Three months ended June 30, 2010 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | | |
| Revenues | 416 | 449 | 2,561 | 79 | - | 3,505 |
| Commodity costs | - | (172) | (2,384) | - | - | (2,556) |
| Operating and administrative | (155) | (123) | (53) | (29) | 1 | (359) |
| Depreciation and amortization | (65) | (77) | (33) | (21) | (2) | (198) |
| | 196 | 77 | 91 | 29 | (1) | 392 |
| Income/(loss) from equity investments | - | - | - | 79 | (8) | 71 |
| Other income/(expense) | 31 | (7) | 4 | 10 | (125) | (87) |
| Interest expense | (55) | (44) | (22) | (14) | (38) | (173) |
| Income taxes | (39) | (4) | (27) | (35) | 56 | (49) |
| Earnings | 133 | 22 | 46 | 69 | (116) | 154 |
| Noncontrolling interests | - | (2) | - | (12) | - | (14) |
| Preferred share dividends | - | - | - | - | (2) | (2) |
| Earnings attributable to Enbridge Inc. common shareholders | 133 | 20 | 46 | 57 | (118) | 138 |
| Additions to property, plant and equipment [1] | 188 | 79 | 222 | 25 | 2 | 516 |
| Total assets | 11,198 | 6,785 | 5,471 | 4,033 | 1,269 | 28,756 |

*1 Includes AEDC*

| **Six months ended June 30, 2011** | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | | |
| Revenues | **982** | **1,534** | **7,006** | **172** | **-** | **9,694** |
| Commodity costs | **-** | **(862)** | **(6,652)** | **-** | **-** | **(7,514)** |
| Operating and administrative | **(317)** | **(226)** | **(114)** | **(57)** | **(10)** | **(724)** |
| Depreciation and amortization | **(161)** | **(158)** | **(83)** | **(49)** | **(5)** | **(456)** |
| | **504** | **288** | **157** | **66** | **(15)** | **1,000** |
| Income from equity investments | **-** | **-** | **-** | **148** | **11** | **159** |
| Other income/(expense) | **71** | **(8)** | **19** | **32** | **-** | **114** |
| Interest expense | **(129)** | **(85)** | **(50)** | **(33)** | **(65)** | **(362)** |
| Income taxes | **(112)** | **(51)** | **(40)** | **(74)** | **41** | **(236)** |
| Earnings | **334** | **144** | **86** | **139** | **(28)** | **675** |
| Noncontrolling interests | **(1)** | **-** | **(1)** | **(17)** | **-** | **(19)** |
| Preferred share dividends | **-** | **-** | **-** | **-** | **(4)** | **(4)** |
| Earnings attributable to Enbridge Inc. common shareholders | **333** | **144** | **85** | **122** | **(32)** | **652** |
| Additions to property, plant and equipment [1] | **399** | **165** | **204** | **40** | **7** | **815** |
| Total assets | **11,903** | **7,014** | **5,550** | **3,772** | **1,884** | **30,123** |

| Six months ended June 30, 2010 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | | |
| Revenues | 738 | 1,493 | 5,093 | 158 | - | 7,482 |
| Commodity costs | - | (842) | (4,783) | - | - | (5,625) |
| Operating and administrative | (274) | (246) | (103) | (56) | (4) | (683) |
| Depreciation and amortization | (130) | (154) | (67) | (42) | (5) | (398) |
| | 334 | 251 | 140 | 60 | (9) | 776 |
| Income from equity investments | - | - | - | 147 | 10 | 157 |
| Other income/(expense) | 95 | (18) | 15 | 19 | (59) | 52 |
| Interest expense | (96) | (88) | (45) | (28) | (66) | (323) |
| Income taxes | (65) | (42) | (40) | (67) | 62 | (152) |
| Earnings | 268 | 103 | 70 | 131 | (62) | 510 |
| Noncontrolling interests | (1) | (3) | - | (22) | - | (26) |
| Preferred share dividends | - | - | - | - | (4) | (4) |
| Earnings attributable to Enbridge Inc. common shareholders | 267 | 100 | 70 | 109 | (66) | 480 |
| Additions to property, plant and equipment [1] | 419 | 142 | 344 | 37 | 1 | 943 |
| Total assets | 11,198 | 6,785 | 5,471 | 4,033 | 1,269 | 28,756 |

*1 Includes AEDC*

## 3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

On June 24, 2011, the National Energy Board (NEB) approved the 10-year Competitive Toll Settlement (CTS) agreement reached between Enbridge and shippers on its crude oil mainline system (Canadian Mainline). The CTS took effect on July 1, 2011. Prior to the CTS, revenue on the Canadian Mainline was recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting guidance. The Company will discontinue the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost-of-service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. Canadian Mainline property, plant and equipment balances as at June 30, 2011 will continue to be recognized at historic cost subject to normal course impairment assessment. As well, the regulatory asset related to future income taxes, which totaled $470 million at June 30, 2011, will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment.

## 4. ACQUISITIONS

On June 30, 2011, the Company invested $144 million to acquire an additional interest in Noverco Inc. (Noverco). Noverco owns approximately 71.0% of Gaz Metro Limited Partnership, a natural gas distribution company. There has been no change in the accounting for the Company's common or preferred share investments in Noverco as a result of the restructuring. The Company's interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

On June 14**,** 2011, the Company acquired an additional 10% interest in Talbot Windfarm, LP (Talbot), a wind energy project, for $28 million, increasing its ownership interest to 100%. The Company's interest in Talbot continues to be held within the Gas Pipelines, Processing and Energy Services segment and is consolidated with the Company's results both before and after the acquisition.

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (HCLP), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in HCLP. Prior to June 16, 2010, the entity was accounted for as a joint venture. The Company's interest in HCLP continues to be held within the Liquids Pipelines segment.

## 5. RISK MANAGEMENT

**Interest Rate Risk**
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest movements. In June 2011, the Company entered into additional derivative instruments to mitigate the volatility of short term interest rates on interest expense through 2015 at an average rate of 2.42%.

At June 30, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in a $4 million increase (2010 - $1 million) in earnings and would have caused a $203 million increase (2010 - $164 million) in Other Comprehensive Income (OCI) due to the revaluation of interest rate derivatives outstanding at June 30, 2011, and a $12 million decrease (2010 - $11 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at June 30, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Earnings for both the three and six months ended June 30, 2011 included a loss of $9 million (2010 - $nil) as a result of hedge ineffectiveness on interest rate derivatives.

**Foreign Exchange and Commodity Price Risk**

As a result of renegotiations with shippers on certain pipelines, the Company is now exposed to additional foreign exchange rate risk on United States dollar denominated revenues, and additional commodity price risk resulting from increased exposure to variable crude oil and power prices.

The Company's earnings, cash flows and OCI are subject to foreign exchange variability, primarily arising from its United States dollar denominated investments, subsidiaries and certain revenues denominated in United States dollars. In June 2011, the Company entered into additional derivative instruments to mitigate cash flow volatility due to the effect of future foreign exchange rate fluctuations.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at June 30, 2011 would have resulted in a $198 million increase to earnings (2010 - $85 million). A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. During the three months ended June 30, 2011, the Company entered into additional power swap and crude oil derivative instruments to fix a portion of the variable price exposures arising from certain commodity agreements.

The Company has defined Earnings at Risk (EaR) limits for different components of businesses exposed to commodity price risk. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. For the six months ended June 30, 2011 and 2010, the Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from total commodity price risk over a one month period:

| | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Average EaR during the year | **23** | 19 |
| High EaR during the year | **27** | 21 |
| Low EaR during the year | **18** | 16 |
| Closing EaR at year end | **25** | 20 |

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

| | **June 30, 2011** | | December 31, 2010 | |
|---|---|---|---|---|
| | Maturity | Notional Principal or Quantity Outstanding | Maturity | Notional Principal or Quantity Outstanding |
| U.S. dollar forwards - purchase *(millions of United States dollars)* | **2011-2020** | **1,303** | 2011-2020 | 1,185 |
| U.S. dollar forwards - sell *(millions of United States dollars)* | **2011-2020** | **7,496** | 2011-2020 | 3,516 |
| Interest rate contracts *(millions of Canadian dollars)* | **2011-2029** | **13,368** | 2011-2029 | 10,772 |
| Commodity contracts - Energy *(bcfe)* | **2011-2013** | **29** | 2011-2013 | 41 |
| Commodity contracts - Power *(MW/H)* | **2011-2024** | **54** | 2011-2024 | 2 |

## 6. STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

## 7. POST EMPLOYMENT BENEFITS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides other post employment benefits (OPEB) for qualifying retired employees. Costs related to the period are presented below.

**NET PENSION PLAN AND OPEB COSTS**

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| Benefits earned during the period | **16** | 14 | **33** | 28 |
| Interest cost on projected benefit obligations | **21** | 21 | **42** | 41 |
| Expected return on plan assets | **(23)** | (21) | **(47)** | (41) |
| Amortization of unrecognized amounts | **6** | 5 | **13** | 10 |
| Amount charged to Enbridge Energy Partners, L.P. (EEP) | **(5)** | (5) | **(10)** | (10) |
| Pension and OPEB Costs | **15** | 14 | **31** | 28 |

The table reflects the pension and OPEB cost for all the Company's benefit plans on an accrual basis. However, for the Gas Distribution pension and OPEB plans, partially offsetting long-term regulatory assets and liabilities have been recorded as plan contributions and actual OPEB benefit costs are recovered through rates.

## 8. COMMITMENTS AND CONTINGENCIES

**COMMITMENTS**

The Company has signed contracts for the purchase of services, pipe and other materials totaling $2,068 million which are expected to be paid within the next five years.

**ENBRIDGE GAS DISTRIBUTION INC.**

**Bloor Street Incident**

Enbridge Gas Distribution Inc. (EGD) was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. EGD commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed EGD's motion, meaning that the

Superior Court's decision ordering a new trial will stand. The new trial is scheduled to commence in November 2011. Management does not believe any fines that may be levied will have a material financial impact on the Company.

**ENBRIDGE ENERGY PARTNERS, L.P.**
**EEP Lakehead System Line 6B and 6A Crude Oil Releases**
Enbridge holds an approximate 25.2% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

*Line 6B Crude Oil Release*
EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. A significant portion of the effort to cleanup, remediate and restore the areas affected by the Line 6B crude oil release was performed by the end of 2010; however, remediation of certain identified sites continues. EEP expects to make payments for additional costs associated with remediation and restoration of the area, air and groundwater monitoring, along with other legal, professional and regulatory costs through future periods. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the incident area to the satisfaction of the appropriate regulatory authorities.

EEP revised its cost estimate for this crude oil release to US$585 million ($101 million after-tax net to Enbridge) at June 30, 2011, an increase of US$35 million ($6 million after-tax net to Enbridge) from March 31, 2011. This estimate is before insurance recoveries and excluding fines and penalties. The expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at June 30, 2011. The estimates do not include amounts capitalized or any fines, penalties and claims associated with the release that may later become evident. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. EEP has the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

*Line 6A Crude Oil Release*
EEP is continuing to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements. The clean up, remediation and restoration of the areas affected by the release has been substantially completed. In connection with this crude oil release, EEP revised its cost estimate to US$48 million ($8 million after-tax net to Enbridge), an increase of US$3 million from March 31, 2011, before insurance recoveries and excluding fines and penalties. EEP has the potential to incur additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation.

*Insurance Recoveries*
The Company maintains commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil releases from Line 6A and 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Assuming all of the claims for the releases are recoverable under this insurance policy, the occurrence-based coverage remaining under the commercial liability insurance policies related to costs associated with Lines 6A and 6B, and other claims of Enbridge and its subsidiaries and affiliates, including EEP, is approximately US$20 million based on estimates as at June 30, 2011. It is anticipated that substantially all of the costs incurred from the crude oil releases will ultimately be recoverable under the Company's existing insurance policies, except for fines and penalties and other amounts for which the Company is not insured. EEP recognized US$15 million ($3 million after-tax net to Enbridge) and US$50 million ($8 million after-tax net to Enbridge) of insurance recoveries in the three and six months ended

June 30, 2011, respectively, for claims filed in connection with the Line 6B crude oil release. Of the US$50 million of insurance recoveries recognized in earnings, EEP received insurance payments of US$35 million in the second quarter of 2011 while the remaining US$15 million is included in EEP's receivables. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period May 1, 2011 through April 30, 2012.

*Legal and Regulatory Proceedings*
A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Currently, approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at June 30, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are operating under an agreed interim order which is expected to mature into a final order in the near future, thereby resolving the proceeding.

**TAX MATTERS**
Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

**OTHER LEGAL AND REGULATORY PROCEEDINGS**
The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## 9. RELATED PARTY TRANSACTIONS

In connection with the Lakehead Line 6B crude oil release, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $2 million and $4 million (2010 - $nil and $nil) for the three and six months ended June 30, 2011.

## 10. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

**EARNINGS**

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars, except per share amounts)* | | | | |
| Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP | **259** | 138 | **652** | 480 |
| Earnings attributable to Enbridge Inc. under Canadian GAAP | **261** | 140 | **656** | 484 |
| Dilution gains, net of tax[1] | **-** | (1) | **-** | (1) |
| Gain on acquisition, net of tax[2] | **-** | 20 | **-** | 20 |
| Inventory valuation adjustment, net of tax[3] | **42** | 2 | **20** | 23 |
| Amortization of underfunded pension adjustment[4] | **(1)** | (1) | **(2)** | (2) |
| Earnings attributable to noncontrolling interests | | | | |
| EEP | **84** | 78 | **145** | 144 |
| Other | **11** | 14 | **19** | 26 |
| Earnings under U.S. GAAP | **397** | 252 | **838** | 694 |
| Less: Earnings attributable to noncontrolling interests | **(95)** | (92) | **(164)** | (170) |
| Earnings attributable to Enbridge Inc. under U.S. GAAP | **302** | 160 | **674** | 524 |
| Preferred share dividends | **(2)** | (2) | **(4)** | (4) |
| Earnings attributable to Enbridge Inc. common shareholders under U.S. GAAP | **300** | 158 | **670** | 520 |
| | | | | |
| Earnings per common share attributable to Enbridge Inc. common shareholders | **0.40** | 0.21 | **0.90** | 0.71 |
| Diluted earnings per common share attributable to Enbridge Inc. common shareholders | **0.39** | 0.21 | **0.88** | 0.70 |

**COMPREHENSIVE INCOME**

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| *(unaudited; millions of Canadian dollars)* | | | | |
| Earnings under U.S. GAAP | **397** | 252 | **838** | 694 |
| Other comprehensive income/(loss) including noncontrolling interests under Canadian GAAP | **(42)** | 107 | **(97)** | (48) |
| Underfunded pension adjustment[4] | **6** | 4 | **9** | 7 |
| Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP[6] | **(2)** | (34) | **(38)** | (30) |
| Other comprehensive income/(loss) including noncontrolling interests under U.S. GAAP | **(38)** | 77 | **(126)** | (71) |
| Comprehensive income | **359** | 329 | **712** | 623 |
| Less: Comprehensive income attributable to noncontrolling interests | **(91)** | (66) | **(108)** | (135) |
| Comprehensive income attributable to Enbridge Inc. under U.S. GAAP | **268** | 263 | **604** | 488 |
| Preferred share dividends | **(2)** | (2) | **(4)** | (4) |
| Comprehensive income attributable to Enbridge Inc. common shareholders under U.S. GAAP | **266** | 261 | **600** | 484 |

**FINANCIAL POSITION**

| | June 30, 2011 | | December 31, 2010 | |
|---|---|---|---|---|
| | **Canada** | **United States** | Canada | United States |
| *(unaudited; millions of Canadian dollars)* | | | | |
| **Assets** | | | | |
| Current assets | | | | |
| Cash and cash equivalents[5,7] | **303** | **425** | 242 | 356 |
| Accounts receivable and other[5,7,9] | **2,334** | **3,118** | 2,706 | 3,582 |
| Inventory[3,5,7] | **672** | **804** | 813 | 913 |
| | **3,309** | **4,347** | 3,761 | 4,851 |
| Property, plant and equipment, net[5,7,9,10] | **20,609** | **28,751** | 20,332 | 28,533 |
| Long-term investments[3,5] | **2,275** | **558** | 2,198 | 413 |
| Deferred amounts and other assets[4,5,7,8,10] | **3,035** | **2,460** | 2,886 | 2,168 |
| Intangible assets[5,9] | **454** | **641** | 478 | 676 |
| Goodwill[5,9] | **383** | **431** | 385 | 445 |
| Future income taxes[7] | **58** | **57** | 80 | 79 |
| | **30,123** | **37,245** | 30,120 | 37,165 |
| **Liabilities and shareholders' equity** | | | | |
| Current liabilities | | | | |
| Short-term borrowings | **238** | **238** | 326 | 326 |
| Accounts payable and other[5,7,9] | **2,339** | **3,343** | 2,688 | 3,798 |
| Interest payable[5] | **113** | **171** | 117 | 177 |
| Current maturities of long-term debt[5] | **3** | **33** | 154 | 185 |
| Current maturities of non-recourse long-term debt[7] | **71** | **70** | 70 | 68 |
| | **2,764** | **3,855** | 3,355 | 4,554 |
| Long-term debt[7,8,9] | **13,624** | **18,461** | 13,561 | 18,358 |
| Non-recourse long-term debt[7] | **1,014** | **665** | 1,061 | 701 |
| Other long-term liabilities[5,6,7,10] | **1,630** | **1,932** | 1,473 | 1,611 |
| Future income taxes[3,4,9] | **2,573** | **2,391** | 2,447 | 2,250 |
| | **21,605** | **27,304** | 21,897 | 27,474 |
| Redeemable noncontrolling interests[6] | **-** | **377** | - | 364 |
| Shareholders' equity | | | | |
| Share capital | | | | |
| Preferred shares | **125** | **125** | 125 | 125 |
| Common shares | **3,827** | **3,827** | 3,683 | 3,683 |
| Contributed surplus | **65** | **-** | 59 | - |
| Retained earnings[3,4,6,9,10] | **5,020** | **4,392** | 4,734 | 4,119 |
| Additional paid-in capital[9] | **-** | **131** | - | 125 |
| Accumulated other comprehensive loss[4] | **(961)** | **(1,089)** | (882) | (1,005) |
| Reciprocal shareholding | **(187)** | **(187)** | (154) | (154) |
| Total Enbridge Inc. shareholders' equity | **7,889** | **7,199** | 7,565 | 6,893 |
| Noncontrolling interests[5,6] | **629** | **2,365** | 658 | 2,434 |
| | **8,518** | **9,564** | 8,223 | 9,327 |
| | **30,123** | **37,245** | 30,120 | 37,165 |

***1 Dilution Gains***

*At June 30, 2010, under Canadian GAAP, dilution gains were recorded as an increase to earnings. Under U.S. GAAP, dilution gains were recorded as equity transactions. At June 30, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists. During the three and six months ended June 30, 2010, $1 million, net of tax, of dilution gains were reclassified from earnings to equity.*

***2 Gain on Acquisition***

*At June 30, 2010, under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control is obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At June 30, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.*

*On June 16, 2010, the Company acquired the remaining 50% interest in HCLP, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in HCLP was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of HCLP, a $20 million gain, net of tax, was recorded in earnings during the three and six months ended June 30, 2010 under U.S GAAP.*

***3 Commodity Inventories Valuation***

*Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the six months ended June, 30, 2011, lower of cost or market adjustments resulted in no change (December 31, 2010 - $33 million decrease) to inventory, a $1 million (December 31, 2010 - $12 million decrease) increase to the future income tax liability and a $20 million (2010 - $21 million) increase to earnings.*

***4 Pension Accounting***

*U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $336 million (December 31, 2010 - $335 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $132 million (December 31, 2010 - $132 million), a decrease in future tax liability of $70 million (December 31, 2010 - $70 million) and an increase in accumulated other comprehensive loss of $136 million (December 31, 2010 - $136 million) at June 30, 2011. Approximately $9 million (2010 - $3 million) related to pension and OPEB plans was reclassified into OCI during the six months ended June 30, 2011.*

*Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At June 30, 2011, this adjustment resulted in a $3 million (December 31, 2010 - $3 million) increase to the net pension asset with an offset to retained earnings.*

*Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At June 30, 2011, this adjustment resulted in an $89 million decrease (December 31, 2010 - $85 million) to regulatory assets with a corresponding decrease to retained earnings, and a $2 million decrease to earnings (2010 - $1 million)*

***5 Consolidation of a Limited Partnership***

*Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 25.2% interest in the partnership, resulting in an increase to assets of $7,917 million (December 31, 2010 - $8,012 million), an increase in liabilities of $6,092 million (December 31, 2010 - $6,140 million) and an increase in noncontrolling interests of $1,825 million (December 31, 2010 - $1,881 million) at June 30, 2011 and no recognition or measurement changes to equity or earnings attributable to the Company as at and for the six months ended June 30, 2011 and 2010.*

***6 Redeemable Noncontrolling Interests***

*Under Canadian GAAP, a subsidiary's redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the consolidated statement of financial position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At June 30, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $284 million (December 31, 2010 - $255 million).*

***7 Accounting for Joint Ventures***

*Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the United States Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.*

***8 Transaction Costs***

*Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in long-term debt. For U.S. GAAP, these costs are reclassified to deferred amounts and other assets. As at June 30, 2011, $88 million (December 31, 2010 - $89 million) of transaction costs were reclassified.*

***9 Common Control Transactions***

*U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At June 30, 2011, a decrease in assets of $404 million (December 31, 2010 - $408 million), a decrease in liabilities of $178 million (December 31, 2010 - $183 million), a decrease in retained earnings of $204 million (December 31, 2010 - $203 million), and a decrease to additional paid-in capital of $22 million (December 31, 2010 - $22 million) related to a historic transaction with Enbridge Income Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was no impact to earnings (2010 - $nil).*

***10 Accounting for Leases***

*The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company's pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $125 million (December 31, 2010 - $129 million), an increase in liabilities of $118 million (December 31, 2010 - $122 million), an increase in retained earnings of $7 million (December 31, 2010 - $7 million) and no change in earnings (December 31, 2010 - $nil).*

# PRO FORMA INCOME STATEMENTS FOR THE 2013 TEST YEAR AND 2012 BRIDGE YEAR

1. This exhibit shows the 2013 test year and 2012 bridge year pro forma income statements for Enbridge Gas Distribution ("EGD") on page 2. The income statements show EGD's corporate consolidated forecast results exclusive of any forecast amounts relating to the Company's non-utility business, St. Lawrence Gas.

2. The 2013 statement does not include within the forecast results the impact of any recovery of the rate increase requested in this rate application.

3. Page 3 of this exhibit shows a reconciliation of the 2013 corporate consolidated forecast income statement to the 2013 Test Year utility income statement found in evidence at Exhibit F3, Tab 1, Schedule 2.

4. Page 4 of this exhibit shows a reconciliation of the 2012 corporate consolidated forecast income statement to the 2012 Bridge Year utility income statement found in evidence at Exhibit F4, Tab 1, Schedule 2.

Witness: K. Culbert

PRO FORMA STATEMENTS OF INCOME
FOR THE YEARS ENDING DECEMBER 31

| Line No. | Description | Col. 1 2013 Test Year ($Millions) | Col. 2 2012 Bridge Year ($Millions) |
|---|---|---|---|
| 1. | Gas sales | 2,217.7 | 2,158.8 |
| 2. | Transportation of gas | 339.6 | 361.4 |
| 3. | Gas costs | (1,548.6) | (1,515.5) |
| 4. | Gas distribution margin | 1,008.7 | 1,004.7 |
| 5. | Transmission, compression & storage | 1.7 | 1.7 |
| 6. | Other revenue | 126.4 | 132.6 |
| 7. | | 1,136.8 | 1,139.0 |
| | Expenses: | | |
| 8. | Operation and maintenance | 443.9 | 420.2 |
| 9. | Depreciation and amortization expense | 302.5 | 291.9 |
| 10. | Fixed financing costs | 2.3 | 2.3 |
| 11. | Debt redemption premium amortization | - | 0.2 |
| 12. | Municipal and other taxes | 40.3 | 39.0 |
| 13. | | 789.0 | 753.6 |
| 14. | Operating Income | 347.8 | 385.4 |
| | Interest expense: | | |
| 16. | Interest on long-term debt | 137.5 | 137.4 |
| 17. | Amortization of preference share issue costs and debt discount and expense | 3.8 | 3.8 |
| 18. | Interest on short-term debt | 19.7 | 15.0 |
| 19. | Interest during construction | (5.0) | (3.8) |
| 20. | Interest due affiliates | 27.0 | 27.0 |
| 21. | | 183.0 | 179.4 |
| 22. | Income before income taxes | 164.8 | 206.0 |
| 23. | Income taxes | 29.2 | 33.5 |
| 24. | Net income | 135.6 | 172.5 |
| 25. | Dividends on preference shares | 4.2 | 3.3 |
| 26. | Earnings applicable to common shares | 131.4 [a] | 169.2 [b] |

Notes:

a) The 2013 earnings of $131.4 million is based on existing rates and does not include any recovery of the rate increase requested by EGD in this proceeding.

b) The 2012 earnings of $169.2 million is based on existing rates and does not include any recovery, or potential rate increase, associated with the outstanding issues in EGD's 2012 rate proceeding EB-2011-0277.

Witness: K. Culbert

RECONCILIATION OF UTILITY INCOME
FOR THE TEST YEAR ENDING DECEMBER 31, 2013

| Line No. | Description | Col. 1<br>Income Per Ex. A3, Tab 2, Sch. 1, p2 (Note a)<br>($Millions) | Col. 2<br>Adjustments<br>($Millions) | Col. 3<br>Utility Income Incl. CIS & Customer Care Per Ex. F3, Tab 1, Sch. 2<br>($Millions) |
|---|---|---|---|---|
| 1. | Gas sales | 2,217.7 | - | 2,217.7 |
| 2. | Transportation of gas | 339.6 | - | 339.6 |
| 3. | Gas costs | (1,548.6) | - | (1,548.6) |
| 4. | Gas distribution margin | 1,008.7 | - | 1,008.7 |
| 5. | Transmission, compression & storage | 1.7 | - | 1.7 |
| 6. | Other revenue | 126.4 | (87.4) [b] | 39.0 |
| 7. | | 1,136.8 | (87.4) | 1,049.4 |
| | Expenses: | | | |
| 8. | Operation and maintenance | 443.9 | (17.8) [c] | 426.1 |
| 9. | Depreciation and amortization expense | 302.5 | (0.2) [c] | 302.3 |
| 10. | Fixed financing costs | 2.3 | - | 2.3 |
| 11. | Debt redemption premium amortization | - | - | - |
| 12. | Municipal and other taxes | 40.3 | (0.2) [c] | 40.1 |
| 13. | | 789.0 | (18.2) | 770.8 |
| 14. | Utility income before income taxes | 347.8 | (69.2) | 278.6 |
| 15. | Utility income taxes | | | 46.7 |
| 16. | Total utility income | | | 231.9 |

Notes:

a) Starting point reconcilation amounts are corporate budget amounts shown within lines 1-14 from page 2, column 1, of this exhibit. Corporate budget amounts for interest expense, dividends and income taxes are excluded from the starting point as interest expense/dividend is treated within the regulatory construct cost of capital determination and income tax is calculated on a utility stand alone basis.

b) Per Exhibit C3, Tab 1, Schedule 1, Pages 3 - 5:

| | |
|---|---|
| Rent from NGV rentals | 0.5 |
| Transactional services | (1.8) |
| Open bill revenue | (1.3) |
| Affiliate asset use revenue | (0.1) |
| ABC T-service (net) | (4.6) |
| Property/asset use revenue 3rd party | (1.4) |
| Miscellaneous | (15.5) |
| Dividend income - Non utility financing transaction (EBO 179-16) | (63.2) |
| | (87.4) |

c) Per Exhibit D3, Tab 1, Schedule 1, Pages 4 & 5:

| | |
|---|---|
| Operation and maintenance | (17.8) |
| Depreciation and amortization expense | (0.2) |
| Municipal and other taxes | (0.2) |
| | (18.2) |

RECONCILIATION OF UTILITY INCOME
FOR THE BRIDGE YEAR ENDING DECEMBER 31, 2012

| Line No. | Description | Col. 1<br>Income Per Ex. A3, Tab 2, Sch. 1, p2 (Note a)<br>($Millions) | Col. 2<br>Adjustments<br>($Millions) | Col. 3<br>Utility Income Per Ex. F4, Tab 1, Sch. 2<br>($Millions) |
|---|---|---|---|---|
| 1. | Gas sales | 2,158.8 | - | 2,158.8 |
| 2. | Transportation of gas | 361.4 | - | 361.4 |
| 3. | Gas costs | (1,515.5) | - | (1,515.5) |
| 4. | Gas distribution margin | 1,004.7 | - | 1,004.7 |
| 5. | Transmission, compression & storage | 1.7 | - | 1.7 |
| 6. | Other revenue | 132.6 | (92.5) [b] | 40.1 |
| 7. | | 1,139.0 | (92.5) | 1,046.5 |
| | Expenses: | | | |
| 8. | Operation and maintenance | 420.2 | (18.0) [c] | 402.2 |
| 9. | Depreciation and amortization expense | 291.9 | (0.3) [c] | 291.6 |
| 10. | Fixed financing costs | 2.3 | - | 2.3 |
| 11. | Debt redemption premium amortization | 0.2 | - | 0.2 |
| 12. | Company share of IR agreement tax savings | - | 25.6 [c] | 25.6 |
| 13. | Municipal and other taxes | 39.0 | (0.2) [c] | 38.8 |
| 14. | | 753.6 | 7.1 | 760.7 |
| 15. | Utility income before income taxes | 385.4 | (99.6) | 285.8 |
| 16. | Utility income taxes | | | 34.0 |
| 17. | Total utility income | | | 251.8 |

Notes:

a) Starting point reconcilation amounts are corporate budget amounts shown within lines 1-14 from page 2, column 2, of this exhibit. Corporate budget amounts for interest expense, dividends and income taxes are excluded from the starting point as interest expense/dividend is treated within the regulatory construct cost of capital determination and income tax is calculated on a utility stand alone basis.

b) Per Exhibit C4, Tab 1, Schedule 1, Pages 2 - 4:

| | |
|---|---|
| Rent from NGV rentals | 0.1 |
| Transactional services | (2.4) |
| Open bill revenue | (1.5) |
| Affiliate asset use revenue | (0.1) |
| ABC T-service (net) | (5.4) |
| Property/asset use revenue 3rd party | (1.4) |
| Miscellaneous | (18.6) |
| Dividend income - Non utility financing transaction (EBO 179-16) | (63.2) |
| | (92.5) |

c) Per Exhibit D4, Tab 1, Schedule 1, Pages 3 & 4:

| | |
|---|---|
| Operation and maintenance | (18.0) |
| Depreciation and amortization expense | (0.3) |
| Company share of IR agreement tax savings | 25.6 |
| Municipal and other taxes | (0.2) |
| | 7.1 |

# FINANCIAL STATEMENTS
## ENBRIDGE GAS DISTRIBUTION HISTORICAL 2010 YEAR

Please see Exhibit A3, Tab 4, Schedule 1, 2010 Annual Report.

Witnesses: J. Jozsa
B. Yuzwa

# ENBRIDGE GAS DISTRIBUTION INC.

## 2010 Annual Report

**Enbridge Gas Distribution Inc.**
500 Consumers Road
Toronto, ON M2J 1P8
Canada

**Mailing Address**
P.O. Box 650
Scarborough, ON M1K 5E3
Canada

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This Management's Discussion and Analysis (MD&A) dated February 18, 2011 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2010, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

## OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc.

## PERFORMANCE OVERVIEW

| Year ended December 31, | 2010 | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| **Earnings Applicable to the Common Shareholder** | **191** | 218 | 207 |
| **Earnings Excluding the Effect of Weather[1]** | **203** | 201 | 184 |
| **Cash Flow Data** | | | |
| Cash provided by operating activities | **503** | 971 | 368 |
| Cash used by investing activities | **(365)** | (384) | (406) |
| Cash (used)/provided by financing activities | **(143)** | (655) | 98 |
| **Dividends** | | | |
| Common share dividends declared | **215** | 188 | 159 |
| Dividends declared per common share | **1.53** | 1.34 | 1.12 |
| Preferred share dividends declared | **2** | 3 | 5 |
| Dividends declared per preferred share | **0.52** | 0.84 | 1.23 |
| **Total Revenues** | **2,475** | 2,903 | 3,105 |
| **Total Assets** | **7,139** | 6,978 | 6,285 |
| **Total Long-Term Liabilities** | **3,871** | 3,547 | 2,556 |

[1] *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by Canadian GAAP. For more information on this non-GAAP measure see page 4.*

### Earnings Applicable to the Common Shareholder

Earnings applicable to the common shareholder were $191 million for the year ended December 31, 2010 compared with $218 million for the year ended December 31, 2009. The decrease of $27 million primarily resulted from warmer weather and higher depreciation and amortization expense, partially offset by customer growth, higher distribution charges and lower income taxes. Depreciation and amortization expense has increased due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

Earnings applicable to the common shareholder were $218 million for the year ended December 31, 2009 compared with $207 million for the year ended December 31, 2008. The increase of $11 million primarily resulted from customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization expense, higher earnings sharing with customers under the current Incentive Regulation (IR) term, higher operating and administrative costs and warmer weather.

## Earnings Excluding the Effect of Weather

| Year ended December 31, | 2010 | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings Applicable to the Common Shareholder | 191 | 218 | 207 |
| Warmer/(colder) than normal weather | 12 | (17) | (23) |
| Earnings Excluding the Effect of Weather | 203 | 201 | 184 |

The effect of weather is measured by heating degree days and is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. Heating degree days is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in the Greater Toronto Area (GTA), using the forecasting methodology approved by the Ontario Energy Board (OEB). Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the recent weather trend.

Earnings excluding the effect of weather were $203 million for the year ended December 31, 2010 compared with $201 million for the year ended December 31, 2009. Earnings increased primarily due to customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation and amortization expense.

Earnings excluding the effect of weather were $201 million for the year ended December 31, 2009 compared with $184 million for the year ended December 31, 2008. Earnings increased primarily due to customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization expense, higher earnings sharing with customers under the current IR term and higher operating and administrative costs.

## Revenues

Revenues for the year ended December 31, 2010 were $2,475 million compared with $2,903 million for the year ended December 31, 2009. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

Revenues for the year ended December 31, 2009 were $2,903 million compared with $3,105 million for the year ended December 31, 2008. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

## Forward-looking Information

*Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.*

*Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a*

*variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.*

*The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, natural gas prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.*

## Non-GAAP Measure

This MD&A contains references to earnings excluding the effect of weather, which represents earnings applicable to the common shareholder adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses this measure to set targets and assess performance of the Company. Earnings excluding the effect of weather is not a measure that has a standardized meaning prescribed by Canadian GAAP and is not considered a Canadian GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

# STRATEGY

The Company's vision is to become North America's leading energy distribution and services company. To achieve its vision, the Company has outlined the following strategic objectives:

- achieve and maintain top decile safety performance;
- deliver shareholder value;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment; and
- enhance governance, integrity and transparency in all business processes.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance during the IR term. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies to support green energy initiatives. In addition, the Company will continue to grow its natural gas storage assets.

# SIGNIFICANT EVENTS

## Customer Care Agreement Extension

In February 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider for call centre services, collections and billing. The contract extension has been structured to provide enhanced levels of customer service. The total cost of the customer care services during the term of the extension is approximately $360 million. To become effective, the recovery of costs associated with this agreement must still be approved by the OEB. Steps are presently being taken by the Company to obtain the OEB's approval in this regard.

## Cost of Capital

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines forecasted a new base level return on equity (ROE) of approximately 9.85% for the Company's 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, the Company anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, the Company has appealed the OEB's May 2010 decision to the Ontario Divisional Court. The Company's appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

## Unregulated Storage Services

The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2010, the Company had expanded its storage capacity by 8% (0.2 billion cubic metres or 7.5 billion cubic feet (bcf)) and sold unregulated storage services into the storage market. A further expansion was approved by the Board of Directors in February 2011 to add an incremental 4.5 bcf of capacity.

## Appointment to the Board of Directors

Effective November 1, 2010 Mr. Stephen J.J. Letwin retired from the Company's Board of Directors and Mr. David T. Robottom, Executive Vice President & Chief Legal Officer of Enbridge Inc., was appointed to the Company's Board of Directors.

# RESULTS OF OPERATIONS

| Year ended December 31, | 2010 | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Gas distribution margin | 995 | 1,025 | 1,011 |
| Other revenue | 108 | 108 | 94 |
| Operating and administrative expenses | (393) | (385) | (374) |
| Depreciation and amortization | (270) | (254) | (239) |
| Municipal and other taxes | (44) | (49) | (47) |
| Earnings sharing | (19) | (19) | (6) |
| Affiliate financing income | 63 | 63 | 63 |
| Interest expense | (186) | (190) | (201) |
| Income taxes | (61) | (78) | (89) |
| Earnings | 193 | 221 | 212 |
| Earnings Applicable to the Common Shareholder | 191 | 218 | 207 |

## Gas Distribution Margin

Gas distribution margin for the year ended December 31, 2010 decreased by $30 million compared with the year ended December 31, 2009. The decrease in gas distribution margin was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2010 were 80 heating degree days warmer compared with forecast heating degree days, with significant variability in the heating degree day profiles of the geographical regions in which the Company operates, unlike what was experienced in the prior year. In 2007, the OEB approved a new method for calculating normal weather in the Company's main franchise area, the GTA. However, prescribed normal weather for the Company's other service regions continues to be based on different forecasting methodologies (also approved by the OEB) than the one now used for the GTA. For the first and fourth quarters of 2010, weather in the other service regions varied from normal to a greater extent than in the GTA, thereby leading to a more significant weather normalization impact on earnings than would be typically expected. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2010 would have been higher by approximately $17 million (2009 - lower by $25 million). Weather, measured in heating degree days, was 3,466 heating degree days for the year ended December 31, 2010 compared with 3,767 heating degree days for the year ended December 31, 2009.

Gas distribution margin for the year ended December 31, 2009 increased by $14 million compared with the year ended December 31, 2008. The increase in gas distribution margin was primarily due to customer growth, favorable changes in customer mix and higher distribution charges as a result of the application of the IR formula approved by the OEB, partially offset by warmer weather compared to the prior year.

The heating degree days reported in 2009 were 253 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2009 would have been lower by approximately $25 million (2008 - $35 million). Weather, measured in heating degree days, was 3,767 degree days for the year ended December 31, 2009 compared with 3,802 heating degree days for the year ended December 31, 2008.

Heating degree days were colder in 2009 and 2008 by a similar magnitude; however, there was a less significant weather normalization impact on 2009 earnings when compared to 2008 earnings due to differences in the pattern of distribution of heating degree days during the year and their relative effectiveness. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

## Other Revenue

Other revenue for the year ended December 31, 2010 was consistent with that of the year ended December 31, 2009. Incremental revenues during the year were derived from the management of fee-for-service energy efficiency initiatives and from unregulated storage operations due to additional contracts for storage services; however, these were offset by the inclusion of interest income in the prior year relating to recovery of a GST overpayment.

Other revenue for the year ended December 31, 2009 increased by $14 million compared with the year ended December 31, 2008. The increase was primarily due to interest income related to the recovery of the GST overpayment and revenue from the unregulated storage business, which was not fully operational in the prior year. This was partially offset by lower Shared Savings Mechanism (SSM) revenue, which results from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers.

## Operating and Administrative

Operating and administrative costs for the year ended December 31, 2010 increased by $8 million compared with the year ended December 31, 2009. The increase was primarily due to higher costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher employee related costs, partially offset by lower customer support related costs relating to the implementation of a new customer billing system in late 2009.

Operating and administrative costs for the year ended December 31, 2009 increased by $11 million compared with the year ended December 31, 2008. The increase was primarily due to higher employee related costs, higher customer support related costs and higher Demand Side Management (DSM) costs incurred in connection with the promotion of energy efficient use of natural gas by customers.

## Depreciation and Amortization

Depreciation and amortization charge for the year ended December 31, 2010 increased by $16 million compared with the year ended December 31, 2009. The increase was primarily due to an increase in the overall asset base mainly resulting from the implementation of a new customer billing system in late 2009.

Depreciation and amortization charge for the year ended December 31, 2009 increased by $15 million compared with the year ended December 31, 2008. The increase was primarily due to an increase in the overall asset base resulting from customer growth, spending on distribution system improvements and new information systems.

## Municipal and Other Taxes

Municipal and other taxes for the year ended December 31, 2010 decreased by $5 million compared with the year ended December 31, 2009. The decrease was primarily due to the elimination of Ontario capital tax, which became effective July 1, 2010.

Municipal and other taxes for the year ended December 31, 2009 increased by $2 million compared with the year ended December 31, 2008. The increase was primarily due to tax related true-ups.

## Earnings Sharing

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the ROE threshold currently applicable to the Company, relating to the approved IR formula for the current fiscal year and relating to the OEB's ROE policy guideline in effect prior to December 2009. The earnings sharing mechanism results in the return of revenue of $19 million to customers for the year ended December 31, 2010 (2009 - $19 million), subject to OEB approval in 2011.

## Interest Expense

Interest expense for the year ended December 31, 2010 decreased by $4 million compared with the year ended December 31, 2009. The decrease was primarily due to the Company's redemption of its $100 million 11.15% debentures in March 2009 and lower credit facility fees resulting from more favourable market conditions.

Interest expense for the year ended December 31, 2009 decreased by $11 million compared with the year ended December 31, 2008. The decrease was primarily due to lower short-term borrowings and lower short-term interest rates. The lower requirement for borrowings was a result of lower working capital requirements due to lower natural gas prices. Partially offsetting the decrease in interest expense were higher credit facility fees.

## Income Taxes

| Year ended December 31, | 2010 | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | 254 | 299 | 301 |
| Income taxes | 61 | 78 | 89 |
| Effective tax rate (%) | 24.0 | 26.1 | 29.6 |

The effective tax rate for the year ended December 31, 2010 was lower compared with the year ended December 31, 2009. The decrease was primarily due to a 1.0% reduction in each of the federal and Ontario income tax rates.

The effective tax rate for the year ended December 31, 2009 was lower compared with the year ended December 31, 2008. The decrease was primarily due to temporary differences relating to the CIS asset and a 0.5% reduction in the federal income tax rate.

## RATE REGULATION

The utility operations of the Company and St. Lawrence are regulated by the OEB and the New York State Public Service Commission (NYSPSC), respectively (collectively the Regulators).

### Incentive Regulation

In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the Settlement Agreement (the Settlement) with customer representatives.

In 2008, the Company moved to an IR methodology. The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

### 2011 Rate Adjustment Application

In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

### 2010 Rate Adjustment Application

In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

### 2009 Rate Adjustment Application

In September 2008, the Company filed an application with the OEB to adjust rates for 2009 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB in December 2008.

The Company received a fiscal 2009 final rate order from the OEB in February 2009 approving the implementation of a rate change effective April 1, 2009, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2009.

### Impact of Rate Regulation

The Company follows Canadian GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Guideline 19 (AcG-19), *Disclosures by Entities Subject to Rate Regulation,* requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2010 Annual Consolidated Financial Statements.

The Company has several instances where the difference between the amount approved by the Regulators for inclusion in regulated rates and the Company's actual experience is deferred until the Regulators approve the refund to or recovery from customers.

The difference between the total natural gas distributed by the Company and the amount of natural gas billed or billable to customers for their recorded consumption, referred to as unaccounted for gas variance, is an example. To the extent the difference varies from the approved amount built into rates, the variance is deferred until the subsequent year, and upon refund or recovery, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved estimate of this variance and the related revenue, rather than the actual variance and related revenue.

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

## LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations, the issuance of commercial paper and credit facility draws, and the issuance of replacement long-term debt to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

A $600 million shelf prospectus filed in May 2008 expired during the second quarter. A new $800 million shelf prospectus was filed in November 2010 and will be effective for a 25 month period. In November 2010, the Company issued $200 million of new 10 year medium-term notes (MTNs) at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%.

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2010.

| | Total Facilities | Credit Facility Draws[1] | Available |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Enbridge Gas Distribution Inc. | 700 | 325 | 375 |
| St. Lawrence Gas Company, Inc. | 12 | 8 | 4 |
| Total Credit Facilities | 712 | 333 | 379 |

[1] *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.*

When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. At December 31, 2010, this ratio was 2.64 (2009 - 2.74). The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test.

Changes in natural gas prices impact accounts receivable and other, gas inventories and accounts payable and other, which may result in the working capital being negative on a temporary basis.

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Accounts receivable and other | 802 | 801 |
| Gas inventories | 400 | 396 |
| Bank overdraft | (18) | (13) |
| Short-term borrowings | (332) | (515) |
| Accounts payable and other | (836) | (781) |
| Working Capital | 16 | (112) |

## Operating Activities

Cash provided by operating activities decreased to $503 million for the year ended December 31, 2010 from $971 million for the year ended December 31, 2009. The decrease primarily resulted from insignificant increases in accounts receivable and gas inventories compared to significant decreases in the prior year. These impacts are primarily the result of fluctuations in the market price of natural gas.

Cash provided by operating activities increased to $971 million for the year ended December 31, 2009 from $368 million for the year ended December 31, 2008. The increase was primarily due to a net inflow in 2009 from changes in working capital, compared to a net outflow in 2008, resulting from significant decreases in accounts receivable and gas inventories compared to increases in the prior year. These impacts were primarily the result of a significant decrease in the price of natural gas in 2009 compared to an increase in 2008.

## Investing Activities

In 2010, cash used for investing activities was $365 million compared with $384 million in 2009, a decrease of $19 million. The decrease was primarily due to spending in the prior year for a new customer billing system, which was implemented in late 2009, partially offset by higher comparative spending in 2010 for distribution system improvements.

Cash used for investing activities for the year ended December 31, 2009 was $384 million compared with $406 million in 2008. The decrease of $22 million was primarily due to higher comparative spending in 2008 for unregulated storage facilities and lower customer-related capital expenditures in the current year.

### Capital Expenditures

| Year ended December 31, | 2010 | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| System improvements and upgrades | 160 | 144 | 154 |
| System expansion | 107 | 107 | 120 |
| Computers and communication equipment | 32 | 73 | 65 |
| Land, structures and improvements | 14 | 3 | 5 |
| Regulated storage | 13 | 3 | 5 |
| Unregulated storage | 7 | 12 | 28 |
| Other | 32 | 28 | 34 |
| Total Capital Expenditures | 365 | 370 | 411 |

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements. The Company expects to spend approximately $500 million in 2011 on capital projects. Annual capital expenditures in recent years have averaged approximately $385 million.

The 2011 capital projects include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

## Financing Activities

In 2010, cash used for financing activities was $143 million compared with $655 million in 2009, a decrease of $512 million. The decrease was primarily due to $400 million of MTN issuances in 2010 and lower net repayments of short-term borrowings compared to the prior year as a result of decreased cash from operating activities, partially offset by a larger debenture maturity and an increase in common share dividends paid compared to the prior year.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2009, the Company did not issue any MTNs. In 2010, the Company had total debenture maturities of $150 million (2009 - $102 million).

The cash used in 2009 compared with cash generated in 2008 was primarily a result of net repayments of short-term borrowings, compared to net issuances of short-term borrowings and debentures in 2008. Increased cash from operating activities and decreased cash required for investing activities reduced financing requirements in 2009.

Short-term borrowings are used primarily to finance working capital, including gas inventories.

### Preferred Shares

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

### Outstanding Share Data[1]

| | Number |
|---|---|
| Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible | 4,000,000 |
| Common Shares | 140,732,747 |

[1] *Outstanding share data information is provided as at February 18, 2011.*

## CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2009 and December 31, 2010.

| Consolidated Statements of Financial Position Category | Increase/ (Decrease) | Explanation |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Property, plant and equipment, net | 168 | Primarily due to capital additions relating to customer growth and system improvements, partially offset by depreciation. |
| Short-term borrowings | (183) | Primarily due to repayments of short-term borrowings using proceeds from a $400 million MTN issue and cash and cash equivalents generated from operations. |
| Accounts payable and other | 55 | Primarily due to higher natural gas purchase liabilities from higher purchased volumes as a result of colder weather during the last month of the year and higher amounts collected from customers under the budget billing program, partially offset by refunds of gas price variances payable to customers. |
| Long-term debt (including current portion) | 252 | Primarily due to a $400 million MTN issue, net of issuance costs, partially offset by a $150 million repayment of debentures. |
| Other long-term liabilities | 86 | Primarily due to increased future removal and site restoration reserves and an increase in the regulatory liability related to pensions. |

## OFF-BALANCE SHEET ARRANGEMENTS

### Gas Held on Behalf of Transportation Service Customers

Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption / replenishment cycle, the Company borrows or loans natural gas from/to transportation service customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2010, $102 million of natural gas was held on behalf of transportation service customers (2009 - $164 million), a change of $62 million compared to the prior year due to lower commodity prices and lower volumes. These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

## CONTINGENCIES AND COMMITMENTS

The Company is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Company's favour, the Company does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Company, taken as a whole.

## Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totalling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2011 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

## Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The

decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Superior Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

## Tax Matters

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

## Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## Contractual Obligations

Payments due for contractual obligations over the next five years and thereafter are as follows:

| | Total | Less than 1 year | 1-3 years | 3-5 years | After 5 years |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Long-term debt [1] | 2,437 | 150 | - | 400 | 1,887 |
| Loans from affiliate company [1] | 375 | - | - | - | 375 |
| Services contract [2] | 22 | 7 | 13 | 2 | - |
| Customer care service contracts [3] | 71 | 57 | 14 | - | - |
| CIS contracts | 9 | 6 | 3 | - | - |
| Gas transportation contracts | 752 | 344 | 247 | 138 | 23 |
| Pension obligations [4] | 9 | 9 | - | - | - |
| Total Contractual Obligations | 3,675 | 573 | 277 | 540 | 2,285 |

[1] *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*

[2] *Primarily fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2010, $124 million (2009 - $112 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*

[3] *In February 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. To become effective, the recovery of costs associated with this agreement must still be approved by the OEB. Steps are presently being taken by the Company to obtain the OEB's approval in this regard.*

[4] *Assumes only required payments will be made into the pension plans in 2011. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2010. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

## QUARTERLY FINANCIAL INFORMATION[1]

| 2010 | Q1 | Q2 | Q3 | Q4 | Total |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Revenues | 1,002 | 423 | 297 | 753 | 2,475 |
| Earnings applicable to the common shareholder | 86 | 28 | 8 | 69 | 191 |

| 2009 | Q1 | Q2 | Q3 | Q4 | Total |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Revenues | 1,353 | 469 | 308 | 773 | 2,903 |
| Earnings/(loss) applicable to the common shareholder | 116 | 32 | (2) | 72 | 218 |

[1] *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

Revenues include amounts billed to customers for natural gas, which varies with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers.

In addition, the Company operates in a seasonal industry. Earnings for interim periods in isolation are not indicative of results for the fiscal year since volumes delivered during the peak winter months are significantly higher.

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

## FOURTH QUARTER 2010 HIGHLIGHTS

Earnings applicable to the common shareholder were $69 million for the three months ended December 31, 2010 compared with $72 million for the same period in 2009. The decrease of $3 million was primarily due to tax differences relating to intangible assets, partially offset by lower interest expense from lower credit facility fees.

## RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

**IPL System Inc.** The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2010, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2010, dividends received amounted to $63 million (2009 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2010 (2009 - $5 million).

**IPL System Inc.** advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2010, interest paid amounted to $27 million (2009 - $27 million) with an outstanding payable balance of $2 million at December 31, 2010 (2009 - $2 million).

**Enbridge (U.S.) Inc.**, an affiliated company under common control, advanced the Company $6 million (2009 - $7 million) at the LIBOR rate plus 0.55%, payable on demand.

**Enbridge Inc.**, the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2010 were $32 million (2009 - $28 million) with an outstanding payable balance of $1 million at December 31, 2010 (2009 - $2 million).

**Gazifère Inc.**, an affiliated company under common control, purchases wholesale services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2010 were $30 million (2009 - $44 million) with an outstanding receivable of $5 million at December 31, 2010 (2009 - $4 million).

**Vector Pipeline Limited Partnership (U.S.)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $27 million (2009 - $29 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

**Vector Pipeline Limited Partnership (Canadian)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $1 million (2009 - $1 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

**Alliance Pipeline Limited Partnership (Canadian)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $25 million (2009 - $24 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

**Alliance Pipeline Limited Partnership (U.S.)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $17 million (2009 - $18 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

**Enbridge Commercial Services Inc.**, an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2010 were $2 million (2009 - $2 million) with an outstanding payable of $nil million at December 31, 2010 (2009 - $nil).

## RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

### Regulatory Risk

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year.

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines forecasted a new base level ROE of approximately 9.85% for the Company's 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, the Company anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, the Company has appealed the OEB's May 2010 decision to the Ontario Divisional Court. The Company's appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

The Settlement allows certain Y and Z factors (which represent specific categories of expense from a Cost of Service (COS) view and uncontrollable external factors, respectively) in the IR formula, which will permit the Company to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to reassess the IR plan and return to COS if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate the Company's risk to factors beyond management's control.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased, including risk management costs for St. Lawrence, and the price approved by the Regulators. This difference is deferred as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

## Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, normally directly impacts earnings of the Company as noted below. Heating degree days is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

| Factor | Incremental change | Approximate incremental impact |
|---|---|---|
| Weather | 18 heating degree days | 1 billion cubic feet |
| Volume | 1 billion cubic feet | $1.3 million (after-tax) |

An unusual pattern of distribution of heating degree days during the year and their relative effectiveness may impact the above sensitivity. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2009 - 81%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where the Company attains its total forecast distribution volume, the Company may not earn the expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers amounts representing variances in the actual and forecast average use by general service customers. The Company remains at risk of distribution volume for large volume contract commercial and industrial customers.

## Market Price Risk

The Company's earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk).

The following section summarizes the primary types of market price risks to which the Company is exposed and outlines the financial derivative hedging programs implemented.

### Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt obligations. Floating to fixed interest rate swaps and options may be used to hedge against the effect of future period interest rate movements. The Company has implemented a hedging program to mitigate the volatility to variable rate interest expense through 2012 at an average rate of 1.8%.

### Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is $nil.

### Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Historically, the Company had managed the exposure to natural gas price risk by entering into fixed price natural gas contracts; however, in compliance with the directive of the OEB, the Company no longer manages the natural gas price risk exposure on behalf of customers other than for St. Lawrence customers. Fluctuations in natural gas prices are borne by the customers.

## Credit Risk

Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty.

## Financing Risk

The Company's financing risk relates to the price volatility and availability of debt to finance capital expenditures and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian debt market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian public capital markets by maintaining a current shelf prospectus with the securities regulators.

## Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments, as they become due. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets.

## Maturities of Derivative Financial Liabilities

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its derivative instruments based on valuation at the balance sheet date.

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Cash inflows | - | - | - | - | - | - |
| Cash outflows | (1) | - | - | - | - | - |
| Net Cash Flows | (1) | - | - | - | - | - |

## Financial Instruments

| December 31, 2010 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Accounts receivable and other | - | - | 722 | - | - | 80 | 802 | 722 |
| Investment in affiliate company | - | 825 | - | - | - | - | 825 | N/A |
| Deferred amounts and other assets | - | - | - | - | - | 487 | 487 | - |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 18 | - | - | - | - | - | 18 | 18 |
| Short-term borrowings | - | - | - | 332 | - | - | 332 | 332 |
| Accounts payable and other | - | - | - | 597 | 1 | 238 | 836 | 598 |
| Long-term debt | - | - | - | 2,417 | - | - | 2,417 | 2,775 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

| December 31, 2009 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Accounts receivable and other | - | - | 691 | - | 2 | 108 | 801 | 693 |
| Investment in affiliate company | - | 825 | - | - | - | - | 825 | N/A |
| Deferred amounts and other assets | - | - | - | - | 4 | 483 | 487 | 4 |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 13 | - | - | - | - | - | 13 | 13 |
| Short-term borrowings | - | - | - | 515 | - | - | 515 | 515 |
| Accounts payable and other | - | - | - | 474 | 3 | 304 | 781 | 477 |
| Long-term debt | - | - | - | 2,165 | - | - | 2,165 | 2,445 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market.*

[2] *Loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined.*

### Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents, bank overdraft and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

## Derivative Instruments

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

| December 31, 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Natural gas *($10^6m^3$)* | 17 | 6 | - | - | - | - |
| Interest rate contracts *(millions of Canadian dollars)* | 279 | 111 | - | - | - | - |
| Net Cash Flows | 296 | 117 | - | - | - | - |

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 13 and 14 of the 2010 Annual Consolidated Financial Statements.

## General Business Risks

### Distribution Operating Risk

The Company's distribution network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, breaks in cast iron pipes, malfunction of compression and decompression equipment and other issues that can lead to outages. Leaks in the distribution system are an inherent risk of operations. A comprehensive surveillance, maintenance and repair program as well as the phased replacement of cast iron pipes significantly reduces the exposure.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage pipeline integrity, which includes the development and use of in-line inspection tools for pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

### Environmental, Health and Safety Risk

The Company's operations are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to GHG emissions.

The Company is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to the shareholder, customers and employees. The Company has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

### Climate Change Legislation

The Canadian Federal Government has indicated that Canada will target a 17% reduction of GHG emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada's electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada's GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations will likely be compatible with those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. The Company continues to monitor developments.

### Reputation Risk

The Company's reputation is very important. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action or increased regulatory oversight.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy, implemented through the Company's Corporate Social Responsibility Policy.

### Workforce

The potential lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human resources is balanced between hiring full-time employees and expanding the contractor workforce.

Approximately 35% of the Company's workforce is represented by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. The current collective agreement with CEPU expired in December 2010 and a new collective agreement is being negotiated. The terms of the prior agreement remain in force until the new agreement is ratified by the union members. Also in December 2010, a four-year collective agreement was signed with the IBEW, expiring in February 2015.

# CRITICAL ACCOUNTING ESTIMATES

## Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

## Depreciation

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2010 of $4,458 million (2009 - $4,290 million), or 62% of total assets (2009 - 62%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2010. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

## Regulatory Assets and Liabilities

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2010, the Company's regulatory assets totaled $296 million (2009 - $299 million) and regulatory liabilities totaled $1,171 million (2009 - $1,165 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

## Post-employment Benefits

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees as well as OPEB to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return.

Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. However, no earnings impact would result due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates.

The Company's plan remains in a surplus position thus precluding any contribution requirements by the Company. The difference between the actual and expected return on plan assets was an excess of $29 million for the year ended December 31, 2010 (2009 - a shortfall of $22 million) as disclosed in Note 17 to the 2010 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, funding in 2011 will be $9 million.

The following sensitivity analysis identifies the impact on the December 31, 2010 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| | Obligation | Expense | Obligation | Expense |
| *(millions of Canadian dollars)* | | | | |
| Decrease in discount rate | 46 | 5 | 6 | - |
| Decrease in expected return on assets | n/a | 3 | n/a | - |
| Decrease in rate of salary increase | (7) | (2) | - | - |

### Contingent Liabilities

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 20 of the 2010 Annual Consolidated Financial Statements.

## REGULATORY GOVERNANCE

### Undertakings

The Company, and its parent Enbridge Inc., have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge Inc. and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB's prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. The Company continues to engage the government, regulators and other stakeholders to determine what alternatives are available to the Company to undertake these investments in the future.

## Affiliate Relationships Code

The Company is subject to the provisions of the OEB's Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

# CHANGE IN ACCOUNTING POLICIES

## Future Accounting Policies

### International Financial Reporting Standards (IFRS)

First-time adoption of Part I - International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V - Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

While the Company's IFRS conversion project was on track to meet the original conversion deadline, the Company has elected to use the one year deferral offered by the Canadian Accounting Standards Board. This decision was made given the continuing uncertainty with respect to the basis of application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business model and performance measurement. The International Accounting Standards Board (IASB) originally issued an exposure draft on rate regulated activities in 2009, but has since failed to finalize the accounting standard or provide definitive guidance on the direction of the project.

During the 2011 deferral period, the Company will present its financial statements in accordance with Part V of the CICA Handbook, will continue to closely monitor developments of the IASB, and will determine whether IFRS or U.S. GAAP would provide the most useful and reliable presentation of its financial results for 2012 and future periods.

### Business Combinations

CICA Handbook Section 1582, Business Combinations, replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of any future business combinations occurring on or after January 1, 2011.

### Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, Consolidated Financial Statements and 1602, Non-controlling Interests, which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

# Financial and Operating Highlights

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| **Financial** *(millions of Canadian dollars)* | | |
| Gas commodity and distribution revenue | 1,977 | 2,346 |
| Transportation of gas for customers | 390 | 449 |
| Other revenue | 108 | 108 |
| Total revenue | 2,475 | 2,903 |
| Gas commodity and distribution costs | (1,372) | (1,770) |
| Net revenue | 1,103 | 1,133 |
| **Earnings** | 193 | 221 |
| **Earnings applicable to the common shareholder** | 191 | 218 |
| **Return on equity[1] (%)** | 10.3 | 11.8 |
| **Operating** | | |
| Volumetric Statistics *(millions of cubic metres)* | | |
| Gas commodity sales | 5,550 | 5,513 |
| Transportation of gas for customers | 5,584 | 6,035 |
| Unbundled volumes[2] | 460 | 341 |
| Total volume | 11,594 | 11,889 |
| Number of active customers[3] *(thousands)* | 1,981 | 1,937 |
| Heating degree days[4] | | |
| Actual | 3,466 | 3,767 |
| Forecast based on normal weather | 3,546 | 3,514 |

[1] *Return on equity data relates to the consolidated entity.*

[2] *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*

[3] *Active customers is the number of natural gas consuming customers at the end of the year.*

[4] *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the GTA.*

# TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

## Financial Reporting

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are not officers or employees of the Company, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Audit, Finance & Risk Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

## Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the Company's Board of Directors, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.



**Janet A. Holder**
President, Gas Distribution



**Narinder K. Kishinchandani**
Vice President, Finance

February 18, 2011

# Independent Auditor's Report

## TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2010 and 2009 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes including a summary of significant accounting policies.

### Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2010 and 2009 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants,
Licensed Public Accountants

Toronto, Ontario

February 18, 2011

# Consolidated Statements of Earnings

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Gas Commodity and Distribution Revenue | 1,977 | 2,346 |
| Transportation of Gas for Customers | 390 | 449 |
| | 2,367 | 2,795 |
| Gas Commodity and Distribution Costs Excluding Depreciation *(Note 19)* | (1,372) | (1,770) |
| Gas Distribution Margin | 995 | 1,025 |
| Other Revenue | 108 | 108 |
| | 1,103 | 1,133 |
| Expenses | | |
| Operating and administrative *(Note 19)* | 393 | 385 |
| Depreciation and amortization | 270 | 254 |
| Municipal and other taxes | 44 | 49 |
| Earnings sharing *(Note 3)* | 19 | 19 |
| | 726 | 707 |
| | 377 | 426 |
| Affiliate Financing Income *(Note 19)* | 63 | 63 |
| Interest Expense *(Notes 9 and 19)* | (186) | (190) |
| | 254 | 299 |
| Income Taxes *(Note 16)* | | |
| Current | (59) | (51) |
| Future | (2) | (27) |
| | (61) | (78) |
| Earnings | 193 | 221 |
| Preferred Share Dividends | (2) | (3) |
| Earnings Applicable to the Common Shareholder | 191 | 218 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Comprehensive Income

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Earnings | 193 | 221 |
| Other Comprehensive (Loss)/Income | | |
| Change in fair value of cash flow hedges, net of tax | (13) | 1 |
| Reclassification to earnings of realized (losses)/gains on cash flow hedges, net of tax | (2) | 2 |
| Change in foreign currency translation adjustment | (1) | (3) |
| Other Comprehensive Loss | (16) | - |
| Comprehensive Income | 177 | 221 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Shareholders' Equity

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Preferred Shares *(Note 11)* | 100 | 100 |
| Common Shares *(Note 11)* | 1,071 | 1,071 |
| Contributed Surplus | 202 | 202 |
| Retained Earnings | | |
| Balance at beginning of year | 596 | 566 |
| Earnings applicable to the common shareholder | 191 | 218 |
| Common share dividends declared | (215) | (188) |
| Balance at End of Year | 572 | 596 |
| Accumulated Other Comprehensive Loss | | |
| Balance at beginning of year | (2) | (2) |
| Other comprehensive loss | (16) | - |
| Balance at End of Year | (18) | (2) |
| Total Shareholders' Equity | 1,927 | 1,967 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Cash Flows

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Operating Activities** | | |
| Earnings | 193 | 221 |
| Depreciation and amortization | 270 | 254 |
| Future income taxes | 2 | 27 |
| Other | 2 | 2 |
| Changes in operating assets and liabilities *(Note 18)* | 31 | 467 |
| Settlement recoverable *(Note 3)* | 5 | - |
| | 503 | 971 |
| **Investing Activities** | | |
| Additions to property, plant and equipment | (345) | (309) |
| Additions to intangible assets | (20) | (61) |
| Change in construction payable | - | (11) |
| Other | - | (3) |
| | (365) | (384) |
| **Financing Activities** | | |
| Net change in short-term borrowings | (182) | (367) |
| Issue of short-term note payable to affiliate company *(Note 19)* | 2 | 6 |
| Repayment of short-term note payable to affiliate company *(Note 19)* | (3) | (6) |
| Debenture and term note issues | 402 | - |
| Debenture and term note repayments | (150) | (102) |
| Preferred share dividends | (2) | (4) |
| Common share dividends | (208) | (181) |
| Other | (2) | (1) |
| | (143) | (655) |
| Increase in Bank Overdraft | (5) | (68) |
| (Bank Overdraft)/Cash and Cash Equivalents at Beginning of Year | (13) | 55 |
| **Bank Overdraft at End of Year** | (18) | (13) |
| **Supplementary Cash Flow Information** | | |
| Income taxes paid | 59 | 113 |
| Interest paid *(Note 9)* | 185 | 187 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Financial Position

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Assets** | | |
| Current Assets | | |
| Accounts receivable and other *(Notes 4 and 19)* | 802 | 801 |
| Gas inventories | 400 | 396 |
| | 1,202 | 1,197 |
| Property, Plant and Equipment, net *(Note 5)* | 4,458 | 4,290 |
| Investment in Affiliate Company *(Note 19)* | 825 | 825 |
| Deferred Amounts and Other Assets *(Note 6)* | 487 | 487 |
| Intangible Assets *(Note 7)* | 167 | 179 |
| | 7,139 | 6,978 |
| **Liabilities and Shareholders' Equity** | | |
| Current Liabilities | | |
| Bank overdraft | 18 | 13 |
| Short-term borrowings *(Note 9)* | 332 | 515 |
| Accounts payable and other *(Notes 8 and 19)* | 836 | 781 |
| Current maturities of long-term debt *(Note 9)* | 150 | 150 |
| Future income taxes *(Note 16)* | 5 | 5 |
| | 1,341 | 1,464 |
| Long-Term Debt *(Note 9)* | 2,267 | 2,015 |
| Other Long-Term Liabilities *(Note 10)* | 1,058 | 972 |
| Future Income Taxes *(Note 16)* | 171 | 185 |
| Loans from Affiliate Company *(Notes 9 and 19)* | 375 | 375 |
| | 5,212 | 5,011 |
| Shareholders' Equity | | |
| Share capital | | |
| Preferred shares *(Note 11)* | 100 | 100 |
| Common shares *(Note 11)* | 1,071 | 1,071 |
| Contributed surplus | 202 | 202 |
| Retained earnings | 572 | 596 |
| Accumulated other comprehensive loss | (18) | (2) |
| | 1,927 | 1,967 |
| Commitments and Contingencies *(Notes 19 and 20)* | | |
| | 7,139 | 6,978 |

*The accompanying notes are an integral part of these consolidated financial statements.*

Approved by the Board of Directors:



**Janet A. Holder**
President, Gas Distribution



**David A. Leslie**
Director

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities (Note 3); allowance for doubtful accounts (Note 4); depreciation rates and carrying values of property, plant and equipment (Note 5); amortization rates of intangible assets (Note 7); fair values of financial instruments (Notes 13 and 14); income taxes (Note 16); post-employment benefits (Note 17); contingencies (Note 20); and fair value of asset retirement obligations. Actual results could differ from these estimates.

### Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments).

### Regulation

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

### Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

### Financial Instruments

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

#### Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and Cash Equivalents and Bank Overdraft as held for trading.

### Available for Sale

The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Such instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies and no external market for the instrument exists. As this investment originated in a related party transaction and has no quoted market price in an active market, it is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established (Note 19).

### Loans and Receivables

Loans and receivables, which include Accounts Receivable and Other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

### Other Financial Liabilities

Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-Term Borrowings, Accounts Payable and Other, Long-Term Debt and Loans from Affiliate Company.

### Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges.

### Cash Flow Hedges

The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other Comprehensive Income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

### Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

## Income Taxes

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

## Foreign Currency Translation

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated Other Comprehensive Loss (AOCL).

## Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a term to maturity of ninety days or less upon issuance.

## Gas Inventories

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred for future collection or refund by the Company to the customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2010, $102 million of natural gas was held on behalf of transportation service customers (December 31, 2009 - $164 million). These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

## Property, Plant and Equipment

Property, plant and equipment are recorded at cost, including associated operating costs and an allowance for interest during construction at current arm's length interest rates.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation.

Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved the by Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

## Deferred Amounts and Other Assets

Deferred amounts and other assets include costs that the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

## Intangible Assets

Intangible assets consist primarily of the Customer Information System (CIS) and software costs, which are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

## Asset Retirement Obligations

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements.

### Post-employment Benefits

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment benefits are determined as follows:

- The cost of pensions and OPEB earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of the expected plan investment performance, salary escalation, retirement ages of employees and expected health-care and insurance costs.
- Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific asset mix within the pension plan. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of employees.
- Pension costs under the defined benefit pension plans have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- The transitional asset and obligation is amortized over the expected average remaining service lives of employees. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension and OPEB regulatory liability and asset has been recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

### Comparative Amounts

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

## 2. CHANGES IN ACCOUNTING POLICIES

### Future Accounting Policy Changes

#### International Financial Reporting Standards

First-time adoption of Part I – International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V – Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

#### Business Combinations

CICA Handbook Section 1582, *Business Combinations,* replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of any future business combinations occurring on or after January 1, 2011.

### Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

## 3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

## Rate Approval

Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flow-through.

## Approved Rates

### Enbridge Gas Distribution

Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2010 (2009 - 8.39%) based on a 36% (2009 - 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

### St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.50% for the year ended December 31, 2010 (2009 - 8.89%) based on a 50% (2009 - 51.5%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11.0% (2009 - 9.6%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact as at December 31, 2010 (2009 - $nil).

## Impacts of Rate Regulation

### Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company generally would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are recorded in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

### Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

## Financial Statement Effects

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

| December 31, | 2010 | 2009 | Consolidated Statements of Financial Position Location** | Estimated Recovery/ Settlement Period (years) | Earnings Impact[1] 2010 | Earnings Impact[1] 2009 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Regulatory Assets/(Liabilities)** | | | | | | |
| Enbridge Gas Distribution | | | | | | |
| Future income taxes [2] | 164 | 174 | DA/OLTL | * | (7) | - |
| OPEB [3] | 68 | 62 | DA | * | 1 | 4 |
| Unaccounted for gas variance [4] | 18 | 10 | AR | 1 | 5 | 6 |
| Settlement recoverable [5] | 15 | 20 | AR/DA | 2 | (3) | - |
| Shared Savings Mechanism [6] | 11 | 14 | AR | * | - | - |
| Average use true-up variance [7] | 4 | 3 | AR | * | 1 | 4 |
| Deferred rate hearing costs [8] | 3 | 6 | AR/DA | 2 | (2) | - |
| Future removal and site restoration reserves [9] | (753) | (692) | OLTL | * | - | - |
| Pension plans [10] | (222) | (205) | OLTL | * | 6 | (6) |
| Purchased gas variance [11] | (144) | (227) | AP | 1 | - | - |
| Earnings sharing deferral [12] | (38) | (25) | AP | 1 | - | - |
| Transactional services deferral [13] | (14) | (14) | AP | 1 | - | - |
| Other regulatory assets and liabilities | 10 | 10 | *** | * | - | (3) |
| | (878) | (864) | | | 1 | 5 |
| St. Lawrence | | | | | | |
| Other regulatory assets and liabilities | 3 | (2) | *** | * | 3 | (1) |
| | 3 | (2) | | | 3 | (1) |
| | (875) | (866) | | | 4 | 4 |

* *Refer to the footnote for details.*

** *AR – Accounts Receivable and Other*
*AP – Accounts Payable and Other*
*DA – Deferred Amounts and Other Assets*
*OLTL – Other Long-Term Liabilities*

****Dependent on the nature of the item.*

[1] *The increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulation recognition of the item, excluding any additional earnings sharing impact. This includes the impact from recovery or refund, during the current year, of items outstanding at the end of the prior year.*

[2] *The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

[3] *The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

[4] *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

[5] *Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.*

[6] *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

[7] *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

[8] *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

[9] *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

[10] *The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.*

[11] *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation, the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.*

[12] *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. The December 31, 2009 balance relates to the years ended December 31, 2009 and 2008. There would be no change in the treatment of this item in the absence of rate regulation.*

[13] *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

## Other Items Affected by Rate Regulation

### Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

### Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2010, costs relating to this services contract of $124 million (2009 - $112 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

### Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

### Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2010, the net book value of these costs was $111 million (2009 - $124 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

### Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2010 is $43 million (2009 - $41 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

### Depreciation

In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

## 4. ACCOUNTS RECEIVABLE AND OTHER

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Trade receivables | 422 | 391 |
| Unbilled revenues | 231 | 222 |
| Agent billing and collection receivable | 86 | 105 |
| Regulatory assets *(Note 3)* | 61 | 67 |
| Due from affiliates *(Note 19)* | 11 | 15 |
| Taxes receivable | 14 | 33 |
| Prepaid expenses | 5 | 8 |
| Other | 23 | 17 |
| Allowance for doubtful accounts | (51) | (57) |
| | 802 | 801 |

## 5. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2010 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Gas mains | 4.2% | 2,505 | 484 | 2,021 |
| Gas services | 4.6% | 2,036 | 628 | 1,408 |
| Regulating and metering equipment | 3.8% | 691 | 224 | 467 |
| Storage | 2.8% | 240 | 79 | 161 |
| Land and right-of-way | 2.6% | 77 | 29 | 48 |
| Computer technology | 19.8% | 33 | 4 | 29 |
| Under construction | - | 66 | - | 66 |
| Other | 3.5% | 259 | 76 | 183 |
| | | 5,907 | 1,524 | 4,383 |
| Unregulated storage | 3.6% | 52 | 2 | 50 |
| Construction materials inventory | - | 25 | - | 25 |
| | | 5,984 | 1,526 | 4,458 |

| December 31, 2009 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Gas mains | 4.2% | 2,373 | 440 | 1,933 |
| Gas services | 4.4% | 1,961 | 594 | 1,367 |
| Regulating and metering equipment | 3.7% | 677 | 216 | 461 |
| Storage | 2.8% | 228 | 73 | 155 |
| Land and right-of-way | 2.5% | 68 | 27 | 41 |
| Computer technology | 19.5% | 27 | 3 | 24 |
| Under construction | - | 71 | - | 71 |
| Other | 3.4% | 247 | 79 | 168 |
| | | 5,652 | 1,432 | 4,220 |
| Unregulated storage | 4.1% | 48 | 1 | 47 |
| Construction materials inventory | - | 23 | - | 23 |
| | | 5,723 | 1,433 | 4,290 |

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $238 million for the year ended December 31, 2010 (2009 - $225 million).

## 6. DEFERRED AMOUNTS AND OTHER ASSETS

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory assets *(Note 3)* | 252 | 259 |
| Pension asset *(Note 17)* | 222 | 205 |
| Long-term portion of derivative assets *(Note 14)* | - | 4 |
| Other | 13 | 19 |
| | 487 | 487 |

## 7. INTANGIBLE ASSETS

| December 31, 2010 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | 20.1% | 100 | 44 | 56 |
| CIS | 10.0% | 127 | 16 | 111 |
| | | 227 | 60 | 167 |

| December 31, 2009 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | 20.5% | 107 | 52 | 55 |
| CIS | 10.5% | 127 | 3 | 124 |
| | | 234 | 55 | 179 |

Intangible assets include $9 million of work-in-progress for the year ended December 31, 2010 (2009 - $9 million). Total amortization expense for intangible assets was $32 million for the year ended December 31, 2010 (2009 - $29 million).

## 8. ACCOUNTS PAYABLE AND OTHER

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Operating accrued liabilities | 282 | 240 |
| Regulatory liabilities *(Note 3)* | 204 | 295 |
| Budget billing plan payable | 92 | 64 |
| Security deposits | 73 | 57 |
| Dividends payable | 54 | 47 |
| Trade payables | 43 | 25 |
| Taxes payable | 34 | 9 |
| Interest payable | 29 | 29 |
| Due to affiliates *(Note 19)* | 3 | 4 |
| Current derivative liabilities *(Note 14)* | 1 | 3 |
| Other | 21 | 8 |
| | 836 | 781 |

## 9. DEBT

| December 31, | Weighted Average Interest Rate | Maturity | 2010 | 2009 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Debentures | 10.46% | 2011-2024 | 235 | 385 |
| Medium-term notes | 5.54% | 2014-2050 | 2,195 | 1,795 |
| Commercial paper and credit facility draws, net | | | 333 | 508 |
| Other | | | 6 | 12 |
| Deferred debt issue costs | | | (20) | (20) |
| Total Debt | | | 2,749 | 2,680 |
| Current Maturities | | | (150) | (150) |
| Short-Term Borrowings | 1.13% | | (332) | (515) |
| Long-Term Debt | | | 2,267 | 2,015 |
| Loans from Affiliate Company | | | 375 | 375 |

Debenture and term note maturities for the years ending December 31, 2011 through 2015 are $150 million, $nil, $nil, $400 million, and $nil, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2011 through 2015 are $138 million, $130 million, $130 million, $124 million and $109 million, respectively.

### Interest Expense

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Debentures and medium-term notes | 149 | 151 |
| Loans from affiliate company *(Note 19)* | 27 | 27 |
| Commercial paper and credit facility draws | 2 | 4 |
| Other interest and finance costs | 11 | 14 |
| Capitalized | (3) | (6) |
| | 186 | 190 |

In 2010, total interest paid to third parties was $158 million (2009 - $160 million) and total interest paid to affiliated companies was $27 million (2009 - $27 million).

### Credit Facilities

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

| December 31, 2010 | Total Facilities | Credit Facility Draws[1] | Available |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Enbridge Gas Distribution Inc. | 700 | 325 | 375 |
| St. Lawrence Gas Company, Inc. | 12 | 8 | 4 |
| Total Credit Facilities | 712 | 333 | 379 |

[1] *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.*

Credit facilities carried a weighted average standby fee of 0.60% per annum from January to July 2010 and 0.38% per annum from

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August to December 2010 on the unused portion and draws bear interest at market rates.

## 10. OTHER LONG-TERM LIABILITIES

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory liabilities *(Note 3)* | 984 | 897 |
| OPEB liabilities *(Note 17)* | 71 | 70 |
| Pension liability *(Note 17)* | 3 | 3 |
| Other | - | 2 |
| | 1,058 | 972 |

## 11. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

### Common Shares

| December 31, | 2010 | | 2009 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| *(millions of Canadian dollars; number of common shares in millions)* | | | | |
| Balance at beginning of year | 141 | 1,071 | 141 | 1,071 |
| Common shares issued | - | - | - | - |
| Balance at End of Year | 141 | 1,071 | 141 | 1,071 |

### Preferred Shares

| December 31, 2010 and 2009 | Authorized | Issued and Outstanding | Amount |
|---|---|---|---|
| *(millions of Canadian dollars, number of preferred shares in millions)* | | | |
| Group 1 | 0.2 | Nil | - |
| Group 2, Series A - C, Cumulative Redeemable Retractable | 6 | Nil | - |
| Group 2, Series D, Cumulative Redeemable Convertible | 4 | Nil | - |
| Group 3, Series A - C, Cumulative Redeemable Retractable | 6 | Nil | - |
| Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible | 4 | 4 | 100 |
| Group 4 | 10 | Nil | - |
| Group 5 | 10 | Nil | - |
| | | | 100 |

Cumulative cash dividends on the Group 3, Series D preferred shares were payable at a fixed yield rate of 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into

Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

## 12. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

### Incentive Stock Options

Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2010, 180,500 stock options (2009 - 244,350 options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $46.59 in 2010 (2009 - $39.61) and a grant date fair value of $6.56 (2009 - $6.73).

### Performance Stock Units

Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2008, 2009, and 2010 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2010, 9,100 PSUs (2009 - 6,900) were issued to employees of the Company.

### Restricted Stock Units

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2010, Enbridge granted 58,750 RSUs (2009 - 61,800) to certain employees of the Company.

### Stock-based Compensation Expense

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2010, the direct charge totaled $6 million (2009 - $5 million) and the allocation totaled $5 million (2009 - $4 million). These costs are included in operating and administrative expenses.

# 13. RISK MANAGEMENT

## Market Price Risk

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

### Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt (commercial paper). Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have caused a $3 million increase (2009 - $15 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2010, and a $nil effect (2009 - $4 million decrease) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

### Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is $nil (2009 - $nil).

### Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

## Total Derivative Instruments

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

| December 31, 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Natural gas *($10^6 m^3$)* | 17 | 6 | - | - | - | - |
| Interest rate contracts *(millions of Canadian dollars)* | 279 | 111 | - | - | - | - |
| Net Cash Flows | 296 | 117 | - | - | - | - |

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $3 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2010.

## Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments (Notes 19 and 20), as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities (Note 9) with a diversified group of banks and institutions which, if necessary, would enable the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

### Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company (Notes 9 and 19).

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Cash inflows | - | - | - | - | - | - |
| Cash outflows | (1) | - | - | - | - | - |
| Net Cash Flows | (1) | - | - | - | - | - |

## Credit Risk

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 14, Fair Value of Financial Instruments.

The change in the allowance for doubtful accounts in respect of accounts receivable is detailed below.

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Balance at beginning of year | (57) | (50) |
| Additional allowance | (23) | (29) |
| Amounts used and reversed | 29 | 22 |
| Balance at End of Year | (51) | (57) |

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. At December 31, 2010, the Company has a maximum exposure to credit risk of $nil (2009 - $3 million) related to its derivative counterparties.

## 14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

| December 31, 2010 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Accounts receivable and other | - | - | 722 | - | - | 80 | 802 | 722 |
| Investment in affiliate company | - | 825 | - | - | - | - | 825 | N/A |
| Deferred amounts and other assets | - | - | - | - | - | 487 | 487 | - |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 18 | - | - | - | - | - | 18 | 18 |
| Short-term borrowings | - | - | - | 332 | - | - | 332 | 332 |
| Accounts payable and other | - | - | - | 597 | 1 | 238 | 836 | 598 |
| Long-term debt | - | - | - | 2,417 | - | - | 2,417 | 2,775 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

| December 31, 2009 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Accounts receivable and other | - | - | 691 | - | 2 | 108 | 801 | 693 |
| Investment in affiliate company | - | 825 | - | - | - | - | 825 | N/A |
| Deferred amounts and other assets | - | - | - | - | 4 | 483 | 487 | 4 |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 13 | - | - | - | - | - | 13 | 13 |
| Short-term borrowings | - | - | - | 515 | - | - | 515 | 515 |
| Accounts payable and other | - | - | - | 474 | 3 | 304 | 781 | 477 |
| Long-term debt | - | - | - | 2,165 | - | - | 2,165 | 2,445 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 19).*

[2] *Loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 19).*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

## Fair Value of Derivatives

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

### Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

### Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

### Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

| December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets: | | | | |
| Current derivative assets | - | - | - | - |
| Long-term derivative assets | - | - | - | - |
| Financial liabilities: | | | | |
| Current derivative liabilities | - | (1) | - | (1) |
| Long-term derivative liabilities | - | - | - | - |
| Total Net Derivative Liability | - | (1) | - | (1) |

| December 31, 2009 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets: | | | | |
| Current derivative assets | - | 2 | - | 2 |
| Long-term derivative assets | - | 4 | - | 4 |
| Financial liabilities: | | | | |
| Current derivative liabilities | - | (3) | - | (3) |
| Long-term derivative liabilities | - | - | - | - |
| Total Net Derivative Asset | - | 3 | - | 3 |

## 15. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings and bank overdraft less cash and cash equivalents.

The Company's capital is calculated as follows:

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Bank overdraft | 18 | 13 |
| Short-term borrowings | 332 | 515 |
| Long-term debt (includes current portion) | 2,437 | 2,185 |
| Loans from affiliate company | 375 | 375 |
| Shareholders' equity | 1,945 | 1,969 |
| Cash and cash equivalents | - | - |
| | 5,107 | 5,057 |

The Company's objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2010, the Company was in compliance with these covenants.

# 16. INCOME TAXES

## Income Tax Rate Reconciliation

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Earnings before income taxes | 254 | 299 |
| Combined statutory income tax rate | 31.0% | 33.0% |
| Income taxes at statutory rate | 79 | 99 |
| Increase/(decrease) resulting from: | | |
| Non-taxable dividend income from affiliated companies | (19) | (21) |
| Future income taxes related to regulated operations | 7 | - |
| Other | (6) | - |
| Income Taxes | 61 | 78 |
| Effective Income Tax Rate | 24% | 26% |

The future income taxes recorded in current liabilities of $5 million (2009 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2010, the Company had a future income tax liability of $164 million (2009 - $174 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

# 17. POST-EMPLOYMENT BENEFITS

## Pension Plans

The Company maintains a non-contributory basic pension plan that provides defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees. The management selected measurement date of December 31, 2010 was used to determine the plan assets and the accrued benefit obligation.

### Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuation and the next required actuarial valuation are as follows:

| Effective Date of Most Recently Filed Actuarial Valuation | Effective Date of Next Required Actuarial Valuation |
|---|---|
| December 31, 2009 | December 31, 2012 |

The defined benefit pension plans' costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

### Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

### Post-employment Benefits Other than Pensions

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

## Defined Benefit Plans

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **December 31,** | **2010** | 2009 | **2010** | 2009 |
| *(millions of Canadian dollars)* | | | | |
| **Change in Accrued Benefit Obligation** | | | | |
| Benefit obligation at beginning of year | **588** | 579 | **81** | 83 |
| Service cost | **12** | 13 | **1** | 1 |
| Interest cost | **39** | 39 | **5** | 6 |
| Actuarial loss/(gain)[1] | **79** | (12) | **5** | (6) |
| Benefits paid | **(31)** | (31) | **(3)** | (3) |
| Net transfer in/(out) | **15** | - | **(2)** | - |
| Benefit obligation at end of year | **702** | 588 | **87** | 81 |
| **Change in Plan Assets** | | | | |
| Fair value of plan assets at beginning of year | **695** | 700 | **-** | - |
| Transfer to the defined contribution component | **(2)** | (1) | **-** | - |
| Actual return on plan assets[1] | **78** | 26 | **-** | - |
| Employer's contributions | **4** | 1 | **7** | 3 |
| Benefits paid | **(31)** | (31) | **(3)** | (3) |
| Net transfer in | **15** | - | **-** | - |
| Fair value of plan assets at end of year | **759** | 695 | **4** | - |
| **Funded Status** | | | | |
| Benefit obligation | **(702)** | (588) | **(87)** | (81) |
| Fair value of plan assets | **759** | 695 | **4** | - |
| Overfunded/(Underfunded) status at end of year | **57** | 107 | **(83)** | (81) |
| Contribution after measurement date | **-** | - | **-** | 1 |
| Unamortized prior service cost | **4** | 5 | **-** | - |
| Unamortized transitional (asset)/obligation | **(70)** | (94) | **16** | 19 |
| Unamortized net actuarial loss/(gain) | **228** | 184 | **(4)** | (9) |
| Net amount recognized in the Consolidated Statement of Financial Position at end of year | **219** | 202 | **(71)** | (70) |
| Presented as follows: | | | | |
| Deferred Amounts and Other Assets *(Note 6)* | **222** | 205 | **-** | - |
| Other Long-Term Liabilities *(Note 10)* | **(3)** | (3) | **(71)** | (70) |

[1] *Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2010** | 2009 | **2010** | 2009 |
| Discount rate | **5.70%** | 6.60% | **5.70%** | 6.60% |
| Average rate of salary increases | **3.50%** | 3.50% | **5.00%** | 5.00% |

### Net Benefit Costs Recognized

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2010** | 2009 | **2010** | 2009 |
| *(millions of Canadian dollars)* | | | | |
| Benefits earned during the year | **12** | 13 | **1** | 1 |
| Interest cost on projected benefit obligations | **39** | 39 | **5** | 6 |
| Actual return on plan assets | **(78)** | (26) | **-** | - |
| Actuarial loss/(gain) | **79** | (12) | **5** | (6) |
| Differences between costs arising in the year and costs recognized in the year: | | | | |
| Return on plan assets | **29** | (22) | **-** | - |
| Prior service costs | **1** | 1 | **-** | - |
| Transitional (asset)/obligation | **(24)** | (25) | **3** | 3 |
| Actuarial (loss)/gain | **(64)** | 25 | **(5)** | 6 |
| Net defined benefit costs on an accrual basis | **(6)** | (7) | **9** | 10 |
| Defined contribution benefit costs | **2** | 1 | **-** | - |
| (Credits)/costs on an accrual basis | **(4)** | (6) | **9** | 10 |

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense is comprised of plan contributions and actual OPEB benefit costs paid, which is consistent with the recovery of such costs in rates. Such costs totaled $4 million for pension benefits and $7 million for OPEB for the year ended December 31, 2010 (2009 - $1 million and $3 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2010** | 2009 | **2010** | 2009 |
| Discount rate | **6.60%** | 6.70% | **6.60%** | 6.70% |
| Average rate of return on pension plan assets | **7.14%** | 7.25% | **-** | - |
| Average rate of salary increases | **3.50%** | 5.00% | **5.00%** | 5.00% |

## Medical Cost Trends

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

| | Medical Cost Trend Rate Assumption for Next Fiscal Year | Ultimate Medical Cost Trend Rate Assumption | Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved |
|---|---|---|---|
| Drugs | 9.13% | 4.50% | 2029 |
| Other Medical and Dental | 4.50% | 4.50% | 2029 |

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

## Plan Assets

### Major Categories of Plan Assets

| | Pension Benefits | | |
|---|---|---|---|
| | 2010 | | 2009 |
| As at December 31, | Allocation | Amount | Allocation |
| *(millions of Canadian dollars)* | | | |
| Equity securities | 58% | 439 | 55% |
| Fixed income securities | 41% | 313 | 41% |
| Other | 1% | 7 | 4% |
| Total Assets | 100% | 759 | 100% |

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

### Target Mix for Plan Assets

| | |
|---|---|
| Equity securities | 52.5% |
| Fixed income securities | 42.5% |
| Other | 5.0% |

## Plan Contributions by the Company

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | 2010 | 2009 | 2010 | 2009 |
| *(millions of Canadian dollars)* | | | | |
| Total contributions | 4 | 1 | 7 | 3 |
| Contributions expected to be paid in 2011 | 5 | | 4 | |

## Benefits Expected to be Paid by the Company

| Year ended December 31, | 2011 | 2012 | 2013 | 2014 | 2015 | 2016-2020 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Expected future benefit payments | 38 | 39 | 41 | 43 | 45 | 255 |

## 18. CHANGES IN OPERATING ASSETS AND LIABILITIES

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Accounts receivable and other | 3 | 187 |
| Gas inventories | (4) | 260 |
| Accounts payable and other | 32 | 20 |
| | 31 | 467 |

## 19. RELATED PARTY TRANSACTIONS

| Year ended December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| IPL System Inc. | | |
| Dividend income | 63 | 63 |
| Interest expense | 27 | 27 |
| Enbridge Inc. | | |
| Purchase of treasury and other management services | 32 | 28 |
| Gazifère Inc. | | |
| Revenue from wholesale service, including gas sales | 30 | 44 |
| Vector Pipeline Limited Partnership (U.S.) | | |
| Purchase of gas transportation services | 27 | 29 |
| Vector Pipeline Limited Partnership (Canadian) | | |
| Purchase of gas transportation services | 1 | 1 |
| Alliance Pipeline Limited Partnership (Canadian) | | |
| Purchase of gas transportation services | 25 | 24 |
| Alliance Pipeline Limited Partnership (U.S.) | | |
| Purchase of gas transportation services | 17 | 18 |
| Enbridge Commercial Services Inc. | | |
| Purchase of information services | 2 | 2 |

The Company had related party balances as follows:

| December 31, | 2010 | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Investment in affiliate company | | |
| IPL System Inc. | 825 | 825 |
| Dividend receivable | 5 | 5 |
| Loans from affiliate company | | |
| IPL System Inc. | 375 | 375 |
| Interest payable | 2 | 2 |
| Note payable to affiliate company | | |
| Enbridge (U.S.) Inc. | 6 | 7 |
| Note receivable from affiliate company | | |
| Enbridge (U.S.) Inc. | - | 4 |
| Accounts receivables/(payables) | | |
| Enbridge Inc. | (1) | (2) |
| Gazifère Inc. | 5 | 4 |

### Financing Transactions

The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2010, the investment of $825 million (2009 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2010, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2010, interest paid amounted to $27 million (2009 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

### Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

### Wholesale Service

These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

### Gas Transportation Services

The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2011 - $67 million, 2012 to 2013 - $133 million, 2014 to 2015 - $114 million and thereafter - $nil.

### Information Services

The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

### Trade Receivables and Payables

The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

## 20. COMMITMENTS AND CONTINGENCIES

### Commitments

The Company has entered into long-term contracts and future payments under the contracts are as follows:

| | Total | Less than 1 year | 1-3 years | 3-5 years | After 5 years |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Services contract[1] | 22 | 7 | 13 | 2 | - |
| Customer care service contracts[2] | 71 | 57 | 14 | - | - |
| CIS contracts[3] | 9 | 6 | 3 | - | - |
| Total Contractual Obligations | 102 | 70 | 30 | 2 | - |

[1] *In 2003, the Company signed a service agreement with Accenture Inc., for a period of ten years, to provide management assistance and information technology solutions for work and asset management and field force transformation. These services relate to system improvement and expansion related construction activities performed by the Company and its construction contractors.*

[2] *In 2007, the Company signed five-year customer care services contracts with third party service providers for meter reading, billing, billing administration, call handling, and collections.*

[3] *In 2007, the Company signed contracts with third party service providers for CIS integration services, software maintenance and support.*

### Contingencies

#### Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2011 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

### Bloor Street Incident

The Company had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

### Tax Matters

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

### Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## TRUSTEE AND REGISTRARS

### Debentures

9.85% and 10.80% debentures

BNY Mellon Trust Company

Corporate Trust Services

320 Bay Street, P.O. Box 1

Toronto, Ontario, M5H 4A6

and in Halifax, Montreal, Winnipeg, Regina, Calgary and Vancouver

For each of the above group of debentures, BNY Mellon Trust Company is the Interest Dispersing Agent.

## REGISTRAR AND PAYING AGENT

### Medium Term Notes

Canadian Imperial Bank of Commerce

Debt Management Service

22 Front Street, 5th Floor

Toronto, Ontario, M5J 2W5

## TRUSTEE

### Medium Term Notes

BNY Mellon Trust Company of Canada

Corporate Trust Services

320 Bay Street, P.O. Box 1

Toronto, Ontario, M5H 4A6

## REGISTRAR AND TRANSFER AGENT

### Group 3 Preferred Shares

Computershare Investor Services Inc.

100 University Avenue

Toronto, Ontario, M5J 2Y1

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite

D.A. Leslie

J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Statement of Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 29, 2010), which is incorporated herein by reference.

# ENBRIDGE GAS DISTRIBUTION INC.

## 2011 Annual Report

**Enbridge Gas Distribution Inc.**
500 Consumers Road
Toronto, ON M2J 1P8
Canada

**Mailing Address**
P.O. Box 650
Scarborough, ON M1K 5E3
Canada

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This Management's Discussion and Analysis (MD&A) dated February 14, 2012 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2011, which are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

## OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

## PERFORMANCE OVERVIEW

| Year ended December 31, | 2011 | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| **Earnings attributable to the common shareholder** | **209** | 191 | 218 |
| **Earnings excluding the effect of weather[1]** | **208** | 203 | 201 |
| **Cash Flow Data** | | | |
| Cash provided by operating activities | **514** | 512 | 953 |
| Cash used by investing activities | **(464)** | (365) | (384) |
| Cash used by financing activities | **(54)** | (154) | (661) |
| **Dividends** | | | |
| Common share dividends declared | **220** | 215 | 188 |
| Dividends declared per common share | **1.56** | 1.53 | 1.34 |
| Preferred share dividends declared | **2** | 2 | 3 |
| Dividends declared per preferred share | **0.60** | 0.52 | 0.84 |
| **Total revenues** | **2,466** | 2,475 | 2,903 |
| **Total assets** | **7,315** | 7,152 | 6,998 |
| **Total long-term liabilities** | **4,054** | 3,871 | 3,547 |

[1] *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by GAAP. For more information on this non-GAAP measure see page 4.*

### Earnings Attributable to the Common Shareholder

Earnings attributable to the common shareholder were $209 million for the year ended December 31, 2011 compared with $191 million for the year ended December 31, 2010. The increase was primarily due to colder weather, lower interest expense, lower income taxes, lower earnings sharing, customer growth and higher distribution charges. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings attributable to the common shareholder were $191 million for the year ended December 31, 2010 compared with $218 million for the year ended December 31, 2009. The decrease primarily resulted from warmer weather and higher depreciation and amortization expense, partially offset by customer growth, higher distribution charges and lower income taxes. Depreciation and amortization expense was higher due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

## Earnings Excluding the Effect of Weather

| Year ended December 31, | 2011 | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings attributable to the common shareholder | 209 | 191 | 218 |
| (Colder)/warmer than normal weather | (1) | 12 | (17) |
| Earnings excluding the effect of weather | 208 | 203 | 201 |

The effect of weather is measured by heating degree days and is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. Heating degree days is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This measure enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in its distribution franchise area, using the forecasting methodology approved by the Ontario Energy Board (OEB). Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the recent weather trend.

Earnings excluding the effect of weather were $208 million for the year ended December 31, 2011 compared with $203 million for the year ended December 31, 2010. The increase was primarily due to lower interest expense, lower income taxes, lower earnings sharing and customer growth. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings excluding the effect of weather were $203 million for the year ended December 31, 2010 compared with $201 million for the year ended December 31, 2009. The increase was primarily due to customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation and amortization expense.

## Revenues

Revenues for the year ended December 31, 2011 were $2,466 million compared with $2,475 million for the year ended December 31, 2010. The decrease in revenues was primarily a result of lower natural gas prices and other revenue, partially offset by colder weather, customer growth and higher distribution charges.

Revenues for the year ended December 31, 2010 were $2,475 million compared with $2,903 million for the year ended December 31, 2009. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

## Forward-looking Information

*Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.*

*Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a*

*variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.*

*The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, natural gas prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.*

### Non-GAAP Measure

This MD&A contains references to earnings excluding the effect of weather, which represents earnings attributable to the common shareholder adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses this measure to set targets and assess performance of the Company. Earnings excluding the effect of weather is not a measure that has a standardized meaning prescribed by GAAP and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

## STRATEGY

The Company's vision is to become North America's leading energy distribution and services company. To achieve its vision, the Company has outlined the following strategic objectives:

- achieve and maintain top decile safety performance;
- deliver shareholder value;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment; and
- enhance governance, integrity and transparency in all business processes.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance during the Incentive Regulation (IR) term. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies. In addition, the Company will continue to grow its natural gas storage assets.

# RECENT DEVELOPMENTS

## Amherstburg Solar Projects

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares. The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge. First Solar Inc. constructed both facilities under fixed price engineering, procurement and construction agreements, and is providing operating and maintenance services for a period of 10 years to both projects, with an optional 10-year renewal. Construction was completed and commercial operations commenced in August 2011. The combined facilities' power output is being sold to the Ontario Power Authority pursuant to 20-year fixed price power purchase agreements. The investment complies with the *Affiliate Relationships Code for Gas Utilities* issued by the OEB and the Company's Undertakings to the Lieutenant Governor in Council for the Province of Ontario.

## Customer Care Agreement Extension

In February 2011, the Company's Board of Directors approved a five-year nine month extension to the Company's customer care services contract with a third party service provider for call centre, collections and billing services. This contract extension is effective April 1, 2012 and has been structured to provide enhanced levels of customer service and cost certainty. The total cost of the customer care services during the term of the extension is approximately $360 million. The Company filed an application with the OEB in June 2011 requesting that the OEB establish a procedure to facilitate the completion of a regulatory settlement agreement and subsequent approval of the rate recovery of the costs associated with the extended customer care services contract and other related costs. The OEB approved the Company's recovery of costs associated with the agreement in September 2011. Other elements of the customer care services also form part of the settlement agreement.

## Cost Of Capital

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The report's new policy guidelines forecasted a new base level return on equity (ROE) of 9.75% for the Company's 2010 rate year, which was higher than the 8.37% generated by the 1997 ROE formula. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. The OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations. The Company appealed the OEB's 2010 decision to the Ontario Divisional Court and the appeal was dismissed by the Divisional Court in March 2011. As a result, earnings sharing will continue to be calculated on the basis of the 1997 ROE formula for the balance of the IR term. The Company has applied for the new ROE to determine rates after the conclusion of the IR term, commencing with the 2013 rate year.

## Unregulated Storage Services And Nexus Project

The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2011, the Company had expanded its storage capacity by 12% (to total capacity of approximately 0.3 billion cubic metres or 12 billion cubic feet (bcf)), compared to pre-deregulation capacity, and sold unregulated storage services into the storage market.

The Nexus Project is a 4.5 bcf expansion of the Company's unregulated natural gas storage facility near Sarnia, Ontario. The project, which has received regulatory approval for construction, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and was completed in 2011 at an approximate capital cost of $34 million. Additional remediation and close-out activities are expected to be performed in 2012 to bring the total capital cost to approximately $38 million.

## Appointment Of New President

Effective September 1, 2011, Mr. Guy Jarvis was appointed as President of the Company. At the same time, Ms. Janet Holder, the Company's previous President, was appointed Executive Vice President, Western Access, Enbridge.

## RESULTS OF OPERATIONS

| Year ended December 31, | 2011 | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Gas distribution margin | 1,021 | 995 | 1,025 |
| Other revenue | 104 | 108 | 108 |
| Operating and administrative expenses | (419) | (393) | (385) |
| Depreciation and amortization | (281) | (270) | (254) |
| Municipal and other taxes | (41) | (44) | (49) |
| Earnings sharing | (13) | (19) | (19) |
| Affiliate financing income | 63 | 63 | 63 |
| Interest expense | (172) | (186) | (190) |
| Income taxes | (51) | (61) | (78) |
| Earnings | 211 | 193 | 221 |
| Earnings attributable to the common shareholder | 209 | 191 | 218 |

### Gas Distribution Margin

Gas distribution margin for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to colder weather, customer growth and higher distribution charges.

The heating degree days reported in 2011 were 5 heating degree days warmer compared with forecast heating degree days. However, due to the relative effectiveness and monthly distribution of heating degree days in the year, on a weather-normalized basis, net gas distribution margin for the year ended December 31, 2011 would have been lower by $1 million (2010 - higher by $17 million). As experienced in 2010, there was significant variability in the 2011 heating degree day profiles of the geographical regions in which the Company operates. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude. Weather, measured in heating degree days, was 3,597 heating degree days for the year ended December 31, 2011 compared with 3,466 heating degree days for the year ended December 31, 2010.

Gas distribution margin for the year ended December 31, 2010 decreased by $30 million compared with the year ended December 31, 2009. The decrease was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2010 were 80 heating degree days warmer compared with forecast heating degree days, with significant variability in the heating degree day profiles of the geographical regions in which the Company operates, unlike what was experienced in 2009. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2010 would have been higher by approximately $17 million (2009 - lower by $25 million). Weather, measured in heating degree days, was 3,466 degree days for the year ended December 31, 2010 compared with 3,767 heating degree days for the year ended December 31, 2009.

### Other Revenue

Other revenue for the year ended December 31, 2011 decreased by $4 million compared with the year ended December 31, 2010. The decrease was primarily due to higher Shared Savings Mechanism revenue in the prior year which resulted from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers. Contributing to the decrease was lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by revenue from Project Amherstburg and higher unregulated storage revenue.

Other revenue for the year ended December 31, 2010 was consistent with that of the year ended December 31, 2009. Incremental revenues during the year were derived from the management of fee-for-service energy efficiency initiatives and from unregulated storage operations due to additional contracts for storage services; however, these were offset by the inclusion of interest income in fiscal 2009 relating to recovery of a GST overpayment.

### Operating and Administrative

Operating and administrative expenses for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to higher employee related costs, higher pipeline integrity and safety costs, and higher customer support related costs.

Operating and administrative expenses for the year ended December 31, 2010 increased by $8 million compared with the year ended December 31, 2009. The increase was primarily due to higher costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher employee related costs, partially offset by lower customer support related costs due to the implementation of a new customer billing system in late 2009.

## Depreciation and Amortization

Depreciation and amortization charge for the year ended December 31, 2011 increased by $11 million compared with the year ended December 31, 2010. Depreciation was higher primarily due to an increase in the overall asset base resulting from customer growth projects and improvements to the distribution system.

Depreciation and amortization charge for the year ended December 31, 2010 increased by $16 million compared with the year ended December 31, 2009. Depreciation was higher primarily due to an increase in the overall asset base mainly resulting from the implementation of a new customer billing system in late 2009.

## Municipal and Other Taxes

Municipal and other taxes for the year ended December 31, 2011 decreased by $3 million compared with the year ended December 31, 2010. The decrease was primarily due to the elimination of Ontario's capital tax in 2010.

Municipal and other taxes for the year ended December 31, 2010 decreased by $5 million compared with the year ended December 31, 2009. The decrease was primarily due to the elimination of Ontario's capital tax.

## Earnings Sharing

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the ROE threshold currently applicable to the Company, relating to the approved IR formula for the current fiscal year and relating to the OEB's ROE policy guideline in effect prior to December 2009. The earnings sharing mechanism resulted in the return of revenue of $13 million to customers for the year ended December 31, 2011 (2010 - $19 million; 2009 - $19 million), subject to OEB approval in 2012. There was approximately $6 million in lower earnings sharing during 2011 as compared to 2010 even though there was no significant variance in regulated earnings. The lower earnings sharing is primary as a result of a higher rate base threshold in 2011 compared to the prior period.

## Interest Expense

Interest expense for the year ended December 31, 2011 decreased by $14 million compared with the year ended December 31, 2010. The decrease was primarily due to the Company's redemption of its $150 million 10.80% debentures in April 2011, which were replaced with the issuance of $100 million medium term notes (MTNs) at 4.95% and additional draws on its credit facilities at lower interest rates.

Interest expense for the year ended December 31, 2010 decreased by $4 million compared with the year ended December 31, 2009. The decrease was primarily due to the Company's redemption of its $100 million 11.15% debentures in March 2009 and lower credit facility fees resulting from more favourable market conditions.

## Income Taxes

| Year ended December 31, | 2011 | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | 262 | 254 | 299 |
| Income taxes | 51 | 61 | 78 |
| Effective tax rate (%) | 19.5 | 24.0 | 26.1 |

The effective tax rate for the year ended December 31, 2011 was lower compared with the year ended December 31, 2010. The decrease was due to temporary differences relating to property, plant and equipment and intangible assets, and an approximate 2.75% reduction in the combined federal and Ontario income tax rates.

The effective tax rate for the year ended December 31, 2010 was lower compared with the year ended December 31, 2009. The decrease was primarily due to a 1.0% reduction in each of the federal and Ontario income tax rates.

## RATE REGULATION

The utility operations of the Company and St. Lawrence are regulated by the OEB and the New York State Public Service Commission (NYSPSC), respectively (collectively the Regulators).

### Incentive Regulation

In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the Settlement Agreement (the Settlement) with customer representatives.

In 2008, the Company moved to an IR methodology. The objectives of the IR Settlement are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

In preparation for the conclusion of the current IR term at the end of 2012, the Company has recently filed a 2013 Cost of Service (COS) application. The Company expects the OEB to address the application in 2012.

### 2012 Rate Adjustment Application

In September 2011, the Company filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The Company applied for distribution revenue of $1,024 million, and $1,004 million or 98%, was approved for recovery by the OEB, pursuant to a settlement agreement with the intervenors representing customers. The rate adjustment was effective January 1, 2012. A hearing with respect to the remaining $20 million applied for distribution revenue and related issues was held by the OEB in January 2012 with a decision expected by April 2012.

### 2011 Rate Adjustment Application

In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

### 2010 Rate Adjustment Application

In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

### Impact of Rate Regulation

The Company follows GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Guideline 19 (AcG-19), *Disclosures by Entities Subject to Rate Regulation*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2011 Annual Consolidated Financial Statements.

The Company has several instances where the difference between the amount approved by the Regulators for inclusion in regulated rates and the Company's actual experience is deferred until the Regulators approve the refund to or recovery from customers.

The difference between the total natural gas distributed by the Company and the amount of natural gas billed or billable to customers for their recorded consumption, referred to as unaccounted for gas variance, is an example. To the extent the difference varies from the approved amount built into rates, the variance is deferred until the subsequent year, and upon refund or recovery, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved estimate of this variance and the related revenue, rather than the actual variance and related revenue.

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Future removal and site restoration reserves, income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

## LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2011, the Company issued additional $100 million additional MTNs under the same terms as the $200 million 40 year MTN pricing supplement issued in 2010 at an interest rate of 4.95%. In 2011, the Company had total debenture maturities of $150 million (2010 - $150 million).

In July 2011, the Company extended the maturity date of the $700 million committed line of credit for an additional year to August 2012, with an additional one-year term out option.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2011.

| | Total Facilities | Credit Facility Draws[1] | Available |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Enbridge Gas Distribution Inc. | 700 | 545 | 155 |
| St. Lawrence Gas Company, Inc. | 12 | 10 | 2 |
| Total credit facilities | 712 | 555 | 157 |

[1] *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

Changes in natural gas prices impact accounts receivable and other, gas inventories and accounts payable and other, which may result in the working capital being negative on a temporary basis.

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Cash and cash equivalents | 9 | 13 |
| Accounts receivable and other | 663 | 802 |
| Gas inventories | 380 | 400 |
| Bank overdraft | (7) | (17) |
| Short-term borrowings | (556) | (332) |
| Accounts payable and other | (713) | (850) |
| Working capital | (224) | 16 |

When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. At December 31, 2011, this ratio was 2.65 (2010 - 2.64). The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test.

## Operating Activities

Cash provided by operating activities was $514 million for the year ended December 31, 2011 compared with $512 million in 2010. The increase was due to a decrease in receivables from customers as a result of the impacts of weather, offset by an increase in the net settlement on purchase gas variances owing to customers.

Cash provided by operating activities was $512 million for the year ended December 31, 2010 compared with $953 million in 2009. The decrease was primarily due to insignificant increases in accounts receivable and gas inventories compared to significant decreases in 2009. These impacts were primarily the result of fluctuations in the market price of natural gas.

## Investing Activities

Cash used for investing activities was $464 million for the year ended December 31, 2011 compared with $365 million in 2010. The increase was primarily due to higher comparative capital spending on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.

Cash used for investing activities was $365 million for the year ended December 31, 2010 compared with $384 million in 2009. The decrease was primarily due to spending in 2009 for a new customer billing system, which was implemented in late 2009, partially offset by higher comparative spending in 2010 for distribution system improvements.

## Capital Expenditures

| Year ended December 31, | 2011 | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| System improvements and upgrades | 159 | 160 | 144 |
| System expansion | 140 | 107 | 107 |
| Computers and communication equipment | 38 | 32 | 73 |
| Unregulated storage | 32 | 7 | 12 |
| Solar assets (Project Amherstburg) | 68 | - | - |
| Other | 106 | 59 | 34 |
| Total capital expenditures | 543 | 365 | 370 |

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements.

The Company expects to spend approximately $440 million in 2012 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $415 million.

The 2012 capital projects include the cast iron replacement program, construction of the technical training facility, the Greater Toronto Area (GTA) reinforcement project and power generation projects. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

## Financing Activities

Cash used for financing activities was $54 million for the year ended December 31, 2011 compared with $154 million in 2010. The decrease was primarily due to issuances of short-term borrowings and the issuance of $100 million MTNs, partially offset by the repayment of the portion of long-term debt that became due.

In 2010, cash used for financing activities was $154 million compared with $661 million in 2009. The decrease was primarily due to $400 million of MTN issuances in 2010 and lower net repayments of short-term borrowings compared to the prior year as a result of decreased cash from operating activities, partially offset by a larger debenture maturity and an increase in common share dividends paid compared to the prior year.

Short-term borrowings are used primarily to finance working capital, including gas inventories.

## Preferred Shares

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

### Outstanding Share Data[1]

| | Number |
|---|---|
| Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible | 4,000,000 |
| Common Shares | 142,345,114 |

[1] *Outstanding share data information is provided as at February 14, 2012.*

## CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2010 and December 31, 2011.

| Consolidated Statements of Financial Position Category | Increase/ (Decrease) | Explanation |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Accounts receivable and other | (139) | Primarily due to warmer weather in the fourth quarter and lower commodity prices. |
| Property, plant and equipment, net | 312 | Primarily due to an increase in the overall asset base resulting from the acquisition of Project Amherstburg assets and expenditures on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility. |
| Short-term borrowings | 224 | Primarily to fund working capital needs. |
| Accounts payable and other | (137) | Primarily due to refunds of gas price variances to customers. |
| Current maturities of long-term debt | (150) | Repayment of the current portion of long-term debt. |
| Long-term debt | 107 | Primarily due to a $100 million MTN issue. |
| Other long-term liabilities | 69 | Primarily due to increased regulatory liabilities from future removal and site restoration reserves and pensions. |
| Share capital – common shares | 66 | Issuance of common shares to fund the Project Amherstburg acquisition. |

## OFF-BALANCE SHEET ARRANGEMENTS

### Gas Held on Behalf of Transportation Service Customers

Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption/replenishment cycle, the Company borrows or loans natural gas from/to transportation service customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

## CONTINGENCIES AND COMMITMENTS

The Company is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Company's favour, the Company does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Company, taken as a whole.

## Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totalling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

## Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

## Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## Contractual Obligations

Payments due for contractual obligations over the next five years and thereafter are as follows:

| | Total | Less than 1 year | 1-3 years | 3-5 years | After 5 years |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Long-term debt[1] | 2,387 | - | 400 | - | 1,987 |
| Loans from affiliate company[1] | 375 | - | - | - | 375 |
| Services contract[2] | 26 | 18 | 8 | - | - |
| Customer care service contracts[3] | 359 | 58 | 115 | 122 | 64 |
| Gas transportation and storage contracts | 927 | 628 | 193 | 90 | 16 |
| Pension and OPEB obligations[4] | 24 | 24 | - | - | - |
| Total contractual obligations | 4,098 | 728 | 716 | 212 | 2,442 |

1 *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*

2 *Consists of fixed overhead payments to contractors and fees relating to services provided for work and asset management initiatives. The majority of the latter expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*

3 *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

4 *Assumes only required payments will be made into the pension and OPEB plans in 2012. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2011. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

## QUARTERLY FINANCIAL INFORMATION

| 2011 | Q1 | Q2 | Q3 | Q4 | Total |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Revenues[1] | 999 | 473 | 315 | 679 | 2,466 |
| Earnings attributable to the common shareholder[1] | 108 | 50 | 9 | 42 | 209 |
| Colder/(warmer) than normal weather | 11 | 2 | - | (12) | 1 |

| 2010 | Q1 | Q2 | Q3 | Q4 | Total |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Revenues[1] | 1,002 | 423 | 297 | 753 | 2,475 |
| Earnings attributable to the common shareholder[1] | 86 | 28 | 8 | 69 | 191 |
| (Warmer)/colder than normal weather | (8) | (10) | - | 6 | (12) |

[1] *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

Revenues include amounts billed to customers for natural gas, which vary with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers.

In addition, the Company operates in a seasonal industry. Earnings for interim periods in isolation are not indicative of results for the fiscal year since volumes delivered during the peak winter months are significantly higher.

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

## FOURTH QUARTER 2011 HIGHLIGHTS

Earnings attributable to the common shareholder were $42 million for the three months ended December 31, 2011 compared with $69 million for the same period in 2010. The decrease was primarily due to warmer weather, lower other revenue, higher operating and administrative expenses, and higher depreciation and amortization expense during the period. This was partially offset by lower income taxes and lower interest expense.

Earnings applicable to the common shareholder were $69 million for the three months ended December 31, 2010 compared with $72 million for the same period in 2009. The decrease of $3 million was primarily due to tax differences relating to intangible assets, partially offset by lower interest expense from lower credit facility fees.

## RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

**IPL System Inc.** The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2011, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2011, dividends received amounted to $63 million (2010 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2011 (2010 - $5 million).

**IPL System Inc.** advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in

either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million) with an outstanding payable balance of $9 million at December 31, 2011 (2010 - $2 million).

**Enbridge (U.S.)**, an affiliated company under common control, advanced a subsidiary of the Company $8 million (2010 - $6 million) at the LIBOR rate plus 0.55%, payable on demand.

**Enbridge**, the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2011 were $34 million (2010 - $32 million) with an outstanding payable balance of $1 million at December 31, 2011 (2010 - $1 million).

**Gazifère Inc.**, an affiliated company under common control, purchases wholesale services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2011 were $28 million (2010 - $30 million) with an outstanding receivable of $4 million at December 31, 2011 (2010 - $5 million).

**Vector Pipeline Limited Partnership (U.S.)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $24 million (2010 - $27 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

**Vector Pipeline Limited Partnership (Canadian)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $2 million (2010 - $1 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

**Alliance Pipeline Limited Partnership (Canadian)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $25 million (2010 - $25 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

**Alliance Pipeline Limited Partnership (U.S.)**, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $18 million (2010 - $17 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

**Enbridge Commercial Services Inc.**, an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2011 were nil (2010 - $2 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

### Other Transactions

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company.

## RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

### Regulatory Risk

The Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year (refer to RECENT DEVELOPMENTS – COST OF CAPITAL).

The Settlement allows certain Y and Z factors (which represent specific categories of expense from a COS view and uncontrollable external factors, respectively) in the IR formula, which will permit the Company to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to reassess the IR plan and return to COS if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate the Company's risk to factors beyond management's control.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the Regulators (including risk management costs for St. Lawrence). This difference is deferred

as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

## Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, normally directly impacts earnings of the Company as noted below. Heating degree days is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

| Factor | Incremental change | Approximate incremental impact |
|---|---|---|
| Weather | 18 heating degree days | 1 billion cubic feet |
| Volume | 1 billion cubic feet | $1.3 million (after-tax) |

An unusual pattern of distribution of heating degree days during the year and their relative effectiveness may impact the above sensitivity. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2010 - 80%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where the Company attains its total forecast distribution volume, the Company may not earn the expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for customers other than large volume transportation customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers amounts representing variances in the actual and forecast average use by general service customers. The Company remains at risk of distribution volume for large volume contract commercial and industrial customers.

## Market Price Risk

The Company's earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following section summarizes the primary types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

### Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future period interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

### Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil.

### Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the OEB's direction. Fluctuations in natural gas prices are borne by the customers.

## Credit Risk

Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty.

## Financing Risk

The Company's financing risk relates to the price volatility and availability of debt to finance capital expenditures and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian debt market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian public capital markets by maintaining a current shelf prospectus with the securities regulators.

## Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments, as they become due. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of replacement debt, commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets.

## Maturities of Derivative Financial Liabilities

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

## Financial Instruments

| December 31, 2011 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Cash and cash equivalents | 9 | - | - | - | - | - | 9 | 9 |
| Accounts receivable and other | - | - | 614 | - | - | 49 | 663 | 614 |
| Investment in affiliate company[2] | - | 825 | - | - | - | - | 825 | N/A |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 7 | - | - | - | - | - | 7 | 7 |
| Short-term borrowings | - | - | - | 556 | - | - | 556 | 556 |
| Accounts payable and other | - | - | - | 654 | 1 | 58 | 713 | 655 |
| Long-term debt | - | - | - | 2,374 | - | - | 2,374 | 2,943 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

| December 31, 2010 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Cash and cash equivalents | 13 | - | - | - | - | - | 13 | 13 |
| Accounts receivable and other | - | - | 722 | - | - | 80 | 802 | 722 |
| Investment in affiliate company[2] | - | 825 | - | - | - | - | 825 | N/A |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 17 | - | - | - | - | - | 17 | 17 |
| Short-term borrowings | - | - | - | 332 | - | - | 332 | 332 |
| Accounts payable and other | - | - | - | 611 | 1 | 238 | 850 | 612 |
| Long-term debt | - | - | - | 2,417 | - | - | 2,417 | 2,775 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market.*

[2] *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined.*

### Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from attributable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents, bank overdraft, and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

## Derivative Instruments

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 14 and 15 of the 2011 Annual Consolidated Financial Statements.

## General Business Risks

### Distribution Network Operating Risk

The Company's distribution network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, breaks in cast iron pipes, malfunction of compression and decompression equipment and other issues that can lead to outages. Leaks in the distribution system are an inherent risk of operations. A comprehensive surveillance, maintenance and repair program as well as the phased replacement of cast iron pipes significantly reduces the exposure.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage pipeline integrity, which includes the development and use of in-line inspection tools for pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

### Environmental, Health and Safety Risk

The Company's operations and facilities are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to GHG emissions.

The Company is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to the shareholder, customers and employees. The Company has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Ongoing training is provided to ensure employee and contractor competency as well as to enhance the safety culture in the Company. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

### Climate Change Legislation

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario and Quebec, as members of the Western Climate Initiative, are implementing reporting and cap and trade programs respectively to meet their stated GHG reduction targets. GHG reporting in Ontario was implemented in 2011, with subsequent years requiring verification of the data submitted. Quebec has announced a pilot cap and trade program prior to proposed regulatory compliance requirements. The Company will continue to monitor provincial developments and respond accordingly.

The Company is on track to deploy a carbon data management system to ensure compliance with 2012 reporting requirements. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

### Reputation Risk

The Company's reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action or increased regulatory oversight.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company's commitment to Green Energy).

## CRITICAL ACCOUNTING ESTIMATES

### Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

### Depreciation

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2011 of $4,770 million (2010 - $4,458 million), or 65% of total assets (2010 - 62%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2011. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

## Regulatory Assets and Liabilities

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2011, the Company's regulatory assets totaled $269 million (2010 - $296 million) and regulatory liabilities totaled $1,076 million (2010 - $1,171 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

## Post-employment Benefits

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and post-employment benefits other than pensions (OPEB) to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return.

Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. However, no earnings impact would result due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates.

The difference between the actual and expected return on plan assets was a shortfall of $38 million for the year ended December 31, 2011 (2010 - $29 million) as disclosed in Note 18 to the 2011 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension and OPEB plans, funding in 2012 will be $24 million.

The following sensitivity analysis identifies the impact on the December 31, 2011 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| | Obligation | Expense | Obligation | Expense |
| *(millions of Canadian dollars)* | | | | |
| Decrease in discount rate | 60 | 6 | 7 | - |
| Decrease in expected return on assets | N/A | 4 | N/A | - |
| Decrease in rate of salary increase | (8) | (2) | - | - |

## Contingent Liabilities

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 21 of the 2011 Annual Consolidated Financial Statements.

# REGULATORY GOVERNANCE

## Undertakings

The Company, and its parent Enbridge, have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB's prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates.

## Affiliate Relationships Code

The Company is subject to the provisions of the OEB's Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

# CHANGES IN ACCOUNTING POLICIES

## Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows or financial position for the year ended December 31, 2011.

## Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

## Future Accounting Policy Changes

### United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of the CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. A rate regulated accounting standard model was not finalized by the International Accounting Standards Board in advance of 2012. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary consolidated financial statements. Management reports regularly to the Audit, Finance & Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

### Accounting and Reporting

The Company is in the process of integrating known U.S. GAAP differences into its primary consolidated financial statements. The most significant differences impact the following areas:

- Push-down accounting as a result of a business combination;
- Pensions and other post-employment benefits; and
- Presentation of deferred financing costs.

The Company will commence reporting using U.S. GAAP as its primary basis of accounting in the first quarter of 2012. To facilitate users' understanding of the transition, subsequent to filing its Canadian GAAP consolidated financial statements for the year ended December 31, 2011 and before filing its first interim report under U.S. GAAP, the Company will be filing, for information purposes, its 2011 comparative consolidated financial statements restated under U.S. GAAP along with comparative periods and related note disclosures.

### Training

The Company has provided U.S. GAAP training to internal personnel impacted by the conversion. U.S. GAAP training will continue into and beyond 2012 as a regular business activity.

### Information Systems and Business Processes

The Company has completed testing system changes necessary to support the conversion to U.S GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Implementation of these changes will take place in the first quarter of 2012. Impacts to internal controls over financial reporting and disclosures have been evaluated and no significant impacts were noted.

### Business Activities

The Company has reviewed the effect of the U.S. GAAP conversion on its debt covenants, compensation agreements and hedging activities, and does not expect the conversion to U.S. GAAP to significantly impact these activities or requirements.

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to economic conditions or other factors.

## ENBRIDGE GAS DISTRIBUTION INC. HIGHLIGHTS

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| **Financial** *(millions of Canadian dollars)* | | |
| Gas commodity and distribution revenue | 2,010 | 1,977 |
| Transportation of gas for customers | 352 | 390 |
| Other revenue | 104 | 108 |
| Total revenue | 2,466 | 2,475 |
| Gas commodity and distribution costs | (1,341) | (1,372) |
| | 1,125 | 1,103 |
| **Earnings** | 211 | 193 |
| **Earnings attributable to the common shareholder** | 209 | 191 |
| **Return on equity[1] (%)** | 11.3 | 10.3 |
| **Operating** | | |
| Volumetric Statistics *(millions of cubic metres)* | | |
| Gas commodity sales | 6,257 | 5,550 |
| Transportation of gas for customers | 5,370 | 5,584 |
| Unbundled volumes[2] | 434 | 460 |
| Total volume | 12,061 | 11,594 |
| Number of active customers[3] *(thousands)* | 1,997 | 1,963 |
| Heating degree days[4] | | |
| Actual | 3,597 | 3,466 |
| Forecast based on normal weather | 3,602 | 3,546 |

[1] *Return on equity data relates to the consolidated entity.*

[2] *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*

[3] *Number of active customers is the number of natural gas consuming customers at the end of the year.*

[4] *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the Greater Toronto Area.*

# TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

## Financial Reporting

Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

## Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.



**D. Guy Jarvis**
President



**Narinder K. Kishinchandani**
Vice President, Finance

February 14, 2012

# Independent Auditor's Report

## TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

### Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2011 and 2010 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants,
Licensed Public Accountants

Toronto, Ontario

February 14, 2012

# Consolidated Statements of Earnings

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Gas commodity and distribution revenue *(Note 20)* | 2,010 | 1,977 |
| Transportation of gas for customers | 352 | 390 |
| | 2,362 | 2,367 |
| Gas commodity and distribution costs excluding depreciation *(Note 20)* | (1,341) | (1,372) |
| Gas distribution margin | 1,021 | 995 |
| Other revenue | 104 | 108 |
| | 1,125 | 1,103 |
| Expenses | | |
| Operating and administrative *(Note 20)* | 419 | 393 |
| Depreciation and amortization | 281 | 270 |
| Municipal and other taxes | 41 | 44 |
| Earnings sharing *(Note 3)* | 13 | 19 |
| | 754 | 726 |
| | 371 | 377 |
| Affiliate financing income *(Note 20)* | 63 | 63 |
| Interest expense *(Notes 10 and 20)* | (172) | (186) |
| | 262 | 254 |
| Income Taxes *(Note 17)* | | |
| Current | (50) | (59) |
| Future | (1) | (2) |
| | (51) | (61) |
| Earnings | 211 | 193 |
| Preferred share dividends | (2) | (2) |
| Earnings attributable to the common shareholder | 209 | 191 |

*The accompanying notes are an integral part of these consolidated financial statements.*

## Consolidated Statements of Comprehensive Income

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Earnings | 211 | 193 |
| Other comprehensive income/(loss) | | |
| Change in unrealized loss on cash flow hedges, net of tax | (1) | (17) |
| Reclassification to earnings of realized gains on cash flow hedges, net of tax | 2 | 2 |
| Change in foreign currency translation adjustment | - | (1) |
| Other comprehensive income/(loss) | 1 | (16) |
| Comprehensive income | 212 | 177 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Shareholders' Equity

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Preferred shares *(Note 12)* | 100 | 100 |
| Common shares *(Note 12)* | | |
| Balance at beginning of year | 1,071 | 1,071 |
| Common shares issued | 66 | - |
| Balance at end of year | 1,137 | 1,071 |
| Contributed surplus | 202 | 202 |
| Retained earnings | | |
| Balance at beginning of year | 572 | 596 |
| Earnings attributable to the common shareholder | 209 | 191 |
| Common share dividends declared | (220) | (215) |
| Balance at end of year | 561 | 572 |
| Accumulated other comprehensive loss | | |
| Balance at beginning of year | (18) | (2) |
| Other comprehensive income | 1 | (16) |
| Balance at end of year | (17) | (18) |
| Total shareholders' equity | 1,983 | 1,927 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Cash Flows

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Operating activities** | | |
| Earnings | 211 | 193 |
| Depreciation and amortization | 281 | 270 |
| Future income taxes | 1 | 2 |
| Other | 4 | 2 |
| Changes in operating assets and liabilities *(Note 19)* | 17 | 45 |
| | 514 | 512 |
| **Investing activities** | | |
| Additions to property, plant and equipment | (441) | (345) |
| Additions to intangible assets | (34) | (20) |
| Change in construction payable | 5 | - |
| Other | 6 | - |
| | (464) | (365) |
| **Financing activities** | | |
| Change in bank overdraft | (10) | (11) |
| Net change in short-term borrowings | 222 | (182) |
| Issue of short-term note payable to affiliate company *(Note 20)* | 5 | 2 |
| Repayment of short-term note payable to affiliate company *(Note 20)* | (3) | (3) |
| Debenture and term note issues | 100 | 402 |
| Debenture and term note repayments | (150) | (150) |
| Preferred share dividends | (2) | (2) |
| Common share dividends | (218) | (208) |
| Other | 2 | (2) |
| | (54) | (154) |
| Decrease in cash and cash equivalents | (4) | (7) |
| Cash and cash equivalents at beginning of year | 13 | 20 |
| **Cash and cash equivalents at end of year** | 9 | 13 |
| **Supplementary cash flow information** | | |
| Income taxes paid | 62 | 59 |
| Interest paid *(Note 10)* | 169 | 185 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# Consolidated Statements of Financial Position

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | 9 | 13 |
| Accounts receivable and other *(Notes 5 and 20)* | 663 | 802 |
| Gas inventories | 380 | 400 |
| | 1,052 | 1,215 |
| Property, plant and equipment, net *(Note 6)* | 4,770 | 4,458 |
| Investment in affiliate company *(Note 20)* | 825 | 825 |
| Deferred amounts and other assets *(Note 7)* | 489 | 487 |
| Intangible assets *(Note 8)* | 179 | 167 |
| | 7,315 | 7,152 |
| **Liabilities and shareholders' equity** | | |
| Current Liabilities | | |
| Bank overdraft | 7 | 17 |
| Short-term borrowings *(Note 10)* | 556 | 332 |
| Accounts payable and other *(Notes 9 and 20)* | 713 | 850 |
| Current maturities of long-term debt *(Note 10)* | - | 150 |
| Future income taxes *(Note 17)* | 2 | 5 |
| | 1,278 | 1,354 |
| Long-term debt *(Note 10)* | 2,374 | 2,267 |
| Other long-term liabilities *(Note 11)* | 1,127 | 1,058 |
| Future income taxes *(Note 17)* | 178 | 171 |
| Loans from affiliate company *(Notes 10 and 20)* | 375 | 375 |
| | 5,332 | 5,225 |
| Shareholders' Equity | | |
| Share capital | | |
| Preferred shares *(Note 12)* | 100 | 100 |
| Common shares *(Note 12)* | 1,137 | 1,071 |
| Contributed surplus | 202 | 202 |
| Retained earnings | 561 | 572 |
| Accumulated other comprehensive loss | (17) | (18) |
| | 1,983 | 1,927 |
| Commitments and contingencies *(Notes 20 and 21)* | | |
| | 7,315 | 7,152 |

*The accompanying notes are an integral part of these consolidated financial statements.*

Approved by the Board of Directors:



**D. Guy Jarvis**
President



**David A. Leslie**
Director

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of the consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; depreciation rates and carrying values of property, plant and equipment *(Note 6)*; amortization rates and carrying values of intangible assets *(Note 8)*; fair values of financial instruments *(Notes 14 and 15)*; income taxes *(Note 17)*; post-employment benefits *(Note 18)*; contingencies *(Note 21)*; and fair value of asset retirement obligations. Actual results could differ from those estimates.

### Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments). All significant intercompany accounts and transactions are eliminated upon consolidation.

### Regulation

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

### Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

## Financial Instruments

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

### Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and cash equivalents and Bank overdraft as held for trading.

### Available for Sale

The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Available for sale instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies. This investment originated in a related party transaction. No external market for the instrument exists and no quoted market price is available in an active market. Therefore, the investment is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 20)*.

### Loans and Receivables

Loans and receivables, which include Accounts receivable and other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

### Other Financial Liabilities

Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Long-term debt and Loans from affiliate company.

### Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges outstanding as at December 31, 2011 and 2010.

### Cash Flow Hedges

The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related nonfinancial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

### Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

### Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

## Income Taxes

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

## Foreign Currency Translation

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated other comprehensive loss (AOCL).

## Gas Inventories

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

## Property, Plant and Equipment

Property, plant and equipment are recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates approved by the Regulators.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

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Tab 4
Schedule 2
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## Deferred Amounts and Other Assets

Deferred amounts and other assets include costs the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

## Intangible Assets

Intangible assets consist primarily of the Customer Information System (CIS), software costs and the Project Amherstburg contracts, which are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

## Asset Retirement Obligations

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements.

## Post-employment Benefits

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment costs are determined as follows:

- The cost of pensions and OPEB earned by employees are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and expected health-care and insurance costs. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- Pension plan assets are measured at fair value.
- The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of the active employee group covered by the plans.
- The transitional asset and obligation is amortized over the expected average remaining service period of the active employee group covered by the plans at the date of transition. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator approved future rates and recovered from, or refunded to, future customers.

## Comparative Amounts

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

## 2. CHANGES IN ACCOUNTING POLICIES

### Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be remeasured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows, or financial position for the year ended December 31, 2011.

### Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and non controlling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

### United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of The CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. The Company believes U.S. GAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated businesses. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

## 3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

### Rate Approval

Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flowthrough.

## Approved Rates

### Enbridge Gas Distribution

Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2011 (2010 - 8.39%) based on a 36% (2010 - 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

### St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2011 (2010 - 10.5%) based on a 50% (2010 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2010 - 11%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact for the years ended December 31, 2011 and December 31, 2010.

## Impacts Of Rate Regulation

### Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

### Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

## Financial Statement Effects

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

| December 31, | 2011 | 2010 | Consolidated Statements of Financial Position Classification** | Estimated Recovery/ Settlement Period *(years)* | Earnings Impact[1] 2011 | Earnings Impact[1] 2010 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Regulatory Assets/(Liabilities)** | | | | | | |
| Enbridge Gas Distribution | | | | | | |
| Future income taxes[2] | 164 | 164 | DA/OLTL | * | - | (7) |
| OPEB[3] | 74 | 68 | DA | * | 4 | 4 |
| Unaccounted for gas variance[4] | 9 | 18 | AR | 1 | (7) | 5 |
| Settlement recoverable[5] | 5 | 15 | AR | 1 | (7) | (3) |
| Deferred rate hearing costs[6] | 3 | 3 | AR/DA | 2 | - | (2) |
| Future removal and site restoration reserves[7] | (815) | (753) | OLTL | * | - | - |
| Pension plans[8] | (231) | (222) | OLTL | * | (6) | (6) |
| Transactional services deferral[9] | (7) | (14) | AP | 1 | - | - |
| Earnings sharing deferral[10] | (14) | (38) | AP | 1 | - | - |
| Average use true-up variance[11] | (3) | 4 | AP/AR | * | (5) | 1 |
| Purchased gas variance[12] | - | (144) | AP | 1 | - | - |
| Shared Savings Mechanism[13] | - | 11 | AR | * | - | - |
| Other regulatory assets and liabilities | 2 | 10 | *** | * | (4) | - |
| | (813) | (878) | | | (25) | (8) |
| St. Lawrence | | | | | | |
| Other regulatory assets and liabilities | 6 | 3 | *** | * | 2 | 3 |
| | 6 | 3 | | | 2 | 3 |
| | (807) | (875) | | | (23) | (5) |

* *Refer to the footnote for details.*

** *AR – Accounts receivable and other*
*AP – Accounts payable and other*
*DA – Deferred amounts and other assets*
*OLTL – Other long-term liabilities*

****Dependent on the nature of the item.*

[1] *The earnings impact represents the increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulated recognition of the item, excluding any additional earnings sharing impact. This includes the impact of items outstanding at the end of the prior year being recovered or refunded in the current year.*

[2] *The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

[3] *The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

[4] *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

[5] *Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.*

[6] *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

[7] *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

[8] *The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.*

[9] *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

[10] *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. There would be no change in the treatment of this item in the absence of rate regulation.*

[11] *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

[12] *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the following quarter via the Quarterly Rate Adjustment Mechanism (QRAM) process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

[13] *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

## Other Items Affected by Rate Regulation

### Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

### Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a service contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, costs relating to this service contract of $133 million (2010 - $124 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

### Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

### Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2011, the net book value of these costs was $99 million (2010 - $111 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

### Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2011 is $42 million (2010 - $43 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

### Depreciation

In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

## 4. ACQUISITION

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares (1,612,367 shares). The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge Inc.

The transaction, which is a related party transaction, has been accounted for at carrying value. The Company consolidates its interest in Project Amherstburg.

Since the acquisition date, Project Amherstburg's revenue and earnings before tax for the year ended December 31, 2011 were $3 million and $2 million, respectively.

| December 31, | 2011 |
|---|---|
| *(millions of Canadian dollars)* | |
| Carrying value of assets acquired: | |
| Property, plant and equipment | 59 |
| Intangible assets | 9 |
| Future income tax liability | (2) |
| | 66 |
| Consideration: | |
| Common shares | 66 |

## 5. ACCOUNTS RECEIVABLE AND OTHER

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Trade receivables | 378 | 422 |
| Unbilled revenues | 175 | 231 |
| Agent billing and collection receivable | 69 | 86 |
| Regulatory assets *(Note 3)* | 24 | 61 |
| Due from affiliates *(Note 20)* | 12 | 11 |
| Taxes receivable | 22 | 14 |
| Prepaid expenses | 3 | 5 |
| Other | 25 | 23 |
| Allowance for doubtful accounts | (45) | (51) |
| | 663 | 802 |

## 6. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2011 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Regulated property, plant and equipment | | | | |
| Gas mains | 4.2% | 2,641 | 528 | 2,113 |
| Gas services | 4.5% | 2,120 | 667 | 1,453 |
| Regulating and metering equipment | 3.7% | 719 | 236 | 483 |
| Gas storage | 3.0% | 275 | 89 | 186 |
| Land and right-of-way | 2.5% | 79 | 30 | 49 |
| Computer technology | 19.8% | 35 | 5 | 30 |
| Under construction | - | 92 | - | 92 |
| Construction materials inventory | - | 39 | - | 39 |
| Other | 3.5% | 259 | 76 | 183 |
| | | 6,259 | 1,631 | 4,628 |
| Unregulated property, plant and equipment | | | | |
| Gas storage | 3.0% | 88 | 4 | 84 |
| Solar assets | 4.0% | 59 | 1 | 58 |
| | | 147 | 5 | 142 |
| | | 6,406 | 1,636 | 4,770 |

| December 31, 2010 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Regulated property, plant and equipment | | | | |
| Gas mains | 4.2% | 2,505 | 484 | 2,021 |
| Gas services | 4.6% | 2,036 | 628 | 1,408 |
| Regulating and metering equipment | 3.8% | 691 | 224 | 467 |
| Gas storage | 2.8% | 240 | 79 | 161 |
| Land and right-of-way | 2.6% | 77 | 29 | 48 |
| Computer technology | 19.8% | 33 | 4 | 29 |
| Under construction | - | 66 | - | 66 |
| Construction materials inventory | - | 25 | - | 25 |
| Other | 3.5% | 259 | 76 | 183 |
| | | 5,932 | 1,524 | 4,408 |
| Unregulated property, plant and equipment | | | | |
| Gas storage | 3.0% | 52 | 2 | 50 |
| | | 52 | 2 | 50 |
| | | 5,984 | 1,526 | 4,458 |

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $250 million for the year ended December 31, 2011 (2010 - $238 million).

## 7. DEFERRED AMOUNTS AND OTHER ASSETS

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory assets *(Note 3)* | 248 | 252 |
| Pension asset *(Note 18)* | 231 | 222 |
| Other | 10 | 13 |
| | 489 | 487 |

## 8. INTANGIBLE ASSETS

| December 31, 2011 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Regulated intangible assets | | | | |
| Software | 20.0% | 111 | 40 | 71 |
| CIS | 10.1% | 127 | 28 | 99 |
| | | 238 | 68 | 170 |
| Unregulated intangible assets | | | | |
| Power purchase contract | 5.0% | 9 | - | 9 |
| | | 9 | - | 9 |
| | | 247 | 68 | 179 |

| December 31, 2010 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Regulated intangible assets | | | | |
| Software | 20.1% | 100 | 44 | 56 |
| CIS | 10.0% | 127 | 16 | 111 |
| | | 227 | 60 | 167 |

Intangible assets include $21 million of work-in-progress for the year ended December 31, 2011 (2010 - $9 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2011 (2010 - $32 million).

## 9. ACCOUNTS PAYABLE AND OTHER

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Operating accrued liabilities | 250 | 282 |
| Regulatory liabilities *(Note 3)* | 32 | 204 |
| Budget billing plan payable | 136 | 92 |
| Security deposits | 79 | 73 |
| Dividends payable | 56 | 54 |
| Trade payables | 67 | 57 |
| Taxes payable | 26 | 34 |
| Interest payable | 26 | 29 |
| Due to affiliates *(Note 20)* | 10 | 3 |
| Current derivative liabilities *(Note 15)* | 1 | 1 |
| Other | 30 | 21 |
| | 713 | 850 |

## 10. DEBT

| December 31, | Weighted Average Interest Rate | Maturity | 2011 | 2010 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Debenture | 9.85% | 2024 | 85 | 235 |
| Medium term notes | 5.51% | 2014-2050 | 2,295 | 2,195 |
| Commercial paper and credit facility draws, net | | | 555 | 333 |
| Other | | | 8 | 6 |
| Deferred debt issue costs | | | (13) | (20) |
| Total debt | | | 2,930 | 2,749 |
| Current maturities | | | - | (150) |
| Short-term borrowings | 1.07% | | (556) | (332) |
| Long-term debt | | | 2,374 | 2,267 |
| Loans from affiliate company | | | 375 | 375 |

Medium term note maturities for the years ending December 31, 2012 through 2016 are nil, nil, $400 million, nil, and nil, respectively. The Company's debenture and medium term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $135 million, $135 million, $129 million, $114 million and $114 million, respectively.

### Interest Expense

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Debenture and medium term notes | 140 | 149 |
| Loans from affiliate company *(Note 20)* | 27 | 27 |
| Commercial paper and credit facility draws | 3 | 2 |
| Other interest and finance costs | 8 | 11 |
| Capitalized | (6) | (3) |
| | 172 | 186 |

In 2011, total interest paid to third parties was $149 million (2010 - $158 million) and total interest paid to affiliated companies was $20 million (2010 - $27 million).

### Credit Facilities

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

| December 31, 2011 | Total Facilities | Credit Facility Draws[1] | Available |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Enbridge Gas Distribution Inc. | 700 | 545 | 155 |
| St. Lawrence Gas Company, Inc. | 12 | 10 | 2 |
| Total credit facilities | 712 | 555 | 157 |

[1] *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

Credit facilities carried a weighted average standby fee of 0.38% per annum from January to July 2011 and 0.22% per annum from August to December 2011 on the unused portion and draws bear interest at market rates.

## 11. OTHER LONG-TERM LIABILITIES

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory liabilities *(Note 3)* | 1,047 | 984 |
| OPEB liabilities *(Note 18)* | 75 | 71 |
| Pension liability *(Note 18)* | 5 | 3 |
| | 1,127 | 1,058 |

## 12. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

### Common Shares

| December 31, | 2011 | | 2010 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| *(millions of Canadian dollars; number of common shares in millions)* | | | | |
| Balance at beginning of year | 140.7 | 1,071 | 140.7 | 1,071 |
| Common shares issued | 1.6 | 66 | - | - |
| Balance at end of year | 142.3 | 1,137 | 140.7 | 1,071 |

### Preferred Shares

| December 31, 2011 and 2010 | Authorized | Issued and Outstanding | Amount |
|---|---|---|---|
| *(millions of Canadian dollars, number of preferred shares in millions)* | | | |
| Group 1 | 0.2 | nil | - |
| Group 2, Series A - C, Cumulative Redeemable Retractable | 6 | nil | - |
| Group 2, Series D, Cumulative Redeemable Convertible | 4 | nil | - |
| Group 3, Series A - C, Cumulative Redeemable Retractable | 6 | nil | - |
| Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible | 4 | 4 | 100 |
| Group 4 | 10 | nil | - |
| Group 5 | 10 | nil | - |
| | | | 100 |

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

## 13. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit were one Enbridge common share and are payable in cash.

### Incentive Stock Options

Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2011, 663,800 stock options (2010 - 361,000 stock options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $28.78 in 2011 (2010 - $23.30) and a grant date fair value of $4.00 (2010 - $3.28).

### Performance Stock Units

Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2009, 2010, and 2011 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2011, 25,200 PSUs (2010 - 18,200) were issued to employees of the Company.

### Restricted Stock Units

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2011, Enbridge granted 111,300 RSUs (2010 - 124,000) to certain employees of the Company.

### Stock-based Compensation Expense

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2011, the total amount of direct charge was $8 million (2010 - $6 million) and the total amount of allocation was $6 million (2010 - $5 million). These costs are included in operating and administrative expenses.

## 14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

### Market Price Risk

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

### Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and would have caused a $1 million increase (2010 - $3 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011, and a $6 million decrease (2010 - $3 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

### Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2010 - nil).

### Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

## Total Derivative Instruments

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $1 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2011.

## Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 20 and 21)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 10)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

### Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 10 and 20)*.

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

## Credit Risk

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 15, *Fair Value of Financial Instruments*.

The change in the allowance for doubtful accounts with respect to accounts receivable is detailed below.

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Balance at beginning of year | (51) | (57) |
| Additional allowance | (25) | (23) |
| Amounts used and reversed | 31 | 29 |
| Balance at end of year | (45) | (51) |

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011, the Company has a maximum exposure to credit risk of nil (2010 - nil) related to its derivative counterparties.

## 15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

| December 31, 2011 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Cash and cash equivalents | 9 | - | - | - | - | - | 9 | 9 |
| Accounts receivable and other | - | - | 614 | - | - | 49 | 663 | 614 |
| Investment in affiliate company[2] | - | 825 | - | - | - | - | 825 | N/A |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 7 | - | - | - | - | - | 7 | 7 |
| Short-term borrowings | - | - | - | 556 | - | - | 556 | 556 |
| Accounts payable and other | - | - | - | 654 | 1 | 58 | 713 | 655 |
| Long-term debt | - | - | - | 2,374 | - | - | 2,374 | 2,943 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

| December 31, 2010 | Held for Trading | Available for Sale | Loans and Receivables | Other Financial Liabilities | Qualifying Hedging Derivatives | Non-Financial Instruments | Total | Fair Value[1] |
|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | |
| **Assets** | | | | | | | | |
| Cash and cash equivalents | 13 | - | - | - | - | - | 13 | 13 |
| Accounts receivable and other | - | - | 722 | - | - | 80 | 802 | 722 |
| Investment in affiliate company[2] | - | 825 | - | - | - | - | 825 | N/A |
| **Liabilities** | | | | | | | | |
| Bank overdraft | 17 | - | - | - | - | - | 17 | 17 |
| Short-term borrowings | - | - | - | 332 | - | - | 332 | 332 |
| Accounts payable and other | - | - | - | 611 | 1 | 238 | 850 | 612 |
| Long-term debt | - | - | - | 2,417 | - | - | 2,417 | 2,775 |
| Loans from affiliate company[2] | - | - | - | 375 | - | - | 375 | N/A |

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 20).*

[2] *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 20).*

The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

## Fair Value of Derivatives

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

### Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

### Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

### Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

At December 31, 2011, the Company has current Level 2 derivative liabilities with fair value of $1 million (2010 - $1 million).

## 16. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings, cash and cash equivalents and bank overdraft.

The Company's capital is calculated as follows:

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Cash and cash equivalents | (9) | (13) |
| Bank overdraft | 7 | 17 |
| Short-term borrowings | 556 | 332 |
| Long-term debt (includes current portion) | 2,387 | 2,437 |
| Loans from affiliate company | 375 | 375 |
| Shareholders' equity | 2,000 | 1,945 |
| | 5,316 | 5,093 |

The Company's objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company's borrowings, whether debentures or medium term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2011, the Company was in compliance with these covenants.

# 17. INCOME TAXES

## Income Tax Rate Reconciliation

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Earnings before income taxes | 262 | 254 |
| Combined statutory income tax rate | 28.3% | 31.0% |
| Income taxes at statutory rate | 74 | 79 |
| Increase/(decrease) resulting from: | | |
| Non-taxable dividend income from affiliated companies | (18) | (19) |
| Future income taxes related to regulated operations | - | 7 |
| Other | (5) | (6) |
| Income taxes | 51 | 61 |
| Effective income tax rate | 19.5% | 24.0% |

The future income taxes recorded in current liabilities of $2 million (2010 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2011, the Company had a future income tax liability of $164 million (2010 - $164 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset *(Note 3)* to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

# 18. POST-EMPLOYMENT BENEFITS

## Pension Plans

The Company provides a non-contributory basic pension plan that provides either defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans which provide pension benefits in excess of the basic plan for certain employees. A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation.

### Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publiclytraded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2009, and the effective date of the next required actuarial valuation is December 31, 2012.

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

### Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

### Post-employment Benefits Other than Pensions

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

## Defined Benefit Plans

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **December 31,** | **2011** | 2010 | **2011** | 2010 |
| *(millions of Canadian dollars)* | | | | |
| **Change in accrued benefit obligation** | | | | |
| Benefit obligation at beginning of year | **702** | 588 | **87** | 81 |
| Service cost | **16** | 12 | **1** | 1 |
| Interest cost | **39** | 39 | **5** | 5 |
| Actuarial loss | **127** | 79 | **13** | 5 |
| Benefits paid | **(33)** | (31) | **(3)** | (3) |
| Other | **1** | 15 | **-** | (2) |
| Benefit obligation at end of year | **852** | 702 | **103** | 87 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | **759** | 695 | **4** | - |
| Transfer to the defined contribution component | **(1)** | (2) | **-** | - |
| Actual return on plan assets | **15** | 78 | **-** | - |
| Employer's contributions | **4** | 4 | **6** | 7 |
| Benefits paid | **(33)** | (31) | **(3)** | (3) |
| Other | **-** | 15 | **(1)** | - |
| Fair value of plan assets at end of year | **744** | 759 | **6** | 4 |
| **Funded status** | | | | |
| Benefit obligation | **(852)** | (702) | **(103)** | (87) |
| Fair value of plan assets | **744** | 759 | **6** | 4 |
| Overfunded/(underfunded) status at end of year | **(108)** | 57 | **(97)** | (83) |
| Unamortized prior service cost | **2** | 4 | **-** | - |
| Unamortized transitional (asset)/obligation | **(44)** | (70) | **13** | 16 |
| Unamortized net actuarial loss/(gain) | **376** | 228 | **9** | (4) |
| Net amount recognized in the Consolidated Statements of Financial Position at end of year | **226** | 219 | **(75)** | (71) |
| Included in the following accounts: | | | | |
| Deferred amounts and other assets *(Note 7)* | **231** | 222 | **-** | - |
| Other long-term liabilities *(Note 11)* | **(5)** | (3) | **(75)** | (71) |

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2011** | 2010 | **2011** | 2010 |
| Discount rate | **4.50%** | 5.70% | **4.50%** | 5.70% |
| Average rate of salary increases | **3.50%** | 3.50% | **5.00%** | 5.00% |

### Net Benefit Costs Recognized

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2011** | 2010 | **2011** | 2010 |
| *(millions of Canadian dollars)* | | | | |
| Benefits earned during the year | **16** | 12 | **1** | 1 |
| Interest cost on projected benefit obligations | **39** | 39 | **5** | 5 |
| Actual return on plan assets | **(15)** | (78) | **-** | - |
| Actuarial loss | **127** | 79 | **13** | 5 |
| Differences between costs arising in the year and costs recognized in the year: | | | | |
| Return on plan assets | **(38)** | 29 | **-** | - |
| Prior service costs | **2** | 1 | **-** | - |
| Transitional (asset)/obligation | **(26)** | (24) | **3** | 3 |
| Actuarial loss | **(110)** | (64) | **(13)** | (5) |
| Net defined benefit costs on an accrual basis | **(5)** | (6) | **9** | 9 |
| Defined contribution benefit costs | **1** | 2 | **-** | - |
| (Credits)/costs on an accrual basis | **(4)** | (4) | **9** | 9 |

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense, which is consistent with the recovery of such costs in rates, was $4 million for pension benefits and $4 million for OPEB for the year ended December 31, 2011 (2010 - $4 million and $4 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| **Year ended December 31,** | **2011** | 2010 | **2011** | 2010 |
| Discount rate | **5.70%** | 6.60% | **5.70%** | 6.60% |
| Average rate of return on pension plan assets | **7.25%** | 7.14% | **-** | - |
| Average rate of salary increases | **3.50%** | 3.50% | **5.00%** | 5.00% |

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## Medical Cost Trends

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

| | Medical Cost Trend Rate Assumption for Next Fiscal Year | Ultimate Medical Cost Trend Rate Assumption | Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved |
|---|---|---|---|
| Drugs | 8.40% | 4.50% | 2029 |
| Other Medical and Dental | 4.50% | 4.50% | 2029 |

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $15 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $12 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

## Plan Assets

### Major Categories of Plan Assets

| | Pension Benefits | | |
|---|---|---|---|
| | 2011 | | 2010 |
| As at December 31, | Allocation | Amount | Allocation |
| *(millions of Canadian dollars)* | | | |
| Equity securities | 55% | 410 | 58% |
| Fixed income securities | 44% | 328 | 41% |
| Other | 1% | 7 | 1% |
| Total assets | 100% | 745 | 100% |

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

### Target Mix for Plan Assets

| | |
|---|---|
| Equity securities | 52.5% |
| Fixed income securities | 42.5% |
| Other | 5.0% |

## Plan Contributions by the Company

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | 2011 | 2010 | 2011 | 2010 |
| *(millions of Canadian dollars)* | | | | |
| Total contributions | 4 | 4 | 6 | 7 |
| Contributions expected to be paid in 2012 | 20 | | 4 | |

### Benefits Expected to be Paid by the Company

| Year ended December 31, | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-2021 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Expected future benefit payments | 39 | 41 | 43 | 45 | 47 | 255 |

## 19. CASH FLOW INFORMATION

### Changes In Operating Assets And Liabilities

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Accounts receivable and other | 139 | 8 |
| Gas inventories | 20 | (4) |
| Accounts payable and other | (142) | 41 |
| | 17 | 45 |

### Significant Non-cash Items

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

## 20. RELATED PARTY TRANSACTIONS

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| IPL System Inc. | | |
| Dividend income | 63 | 63 |
| Interest expense | 27 | 27 |
| Enbridge Inc. | | |
| Purchase of treasury and other management services | 34 | 32 |
| Gazifère Inc. | | |
| Revenue from wholesale service, including gas sales | 28 | 30 |
| Vector Pipeline Limited Partnership (U.S.) | | |
| Purchase of gas transportation services | 24 | 27 |
| Vector Pipeline Limited Partnership (Canadian) | | |
| Purchase of gas transportation services | 2 | 1 |
| Alliance Pipeline Limited Partnership (Canadian) | | |
| Purchase of gas transportation services | 25 | 25 |
| Alliance Pipeline Limited Partnership (U.S.) | | |
| Purchase of gas transportation services | 18 | 17 |
| Enbridge Commercial Services Inc. | | |
| Purchase of information services | - | 2 |

The Company had related party balances as follows:

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Investment in affiliate company | | |
| IPL System Inc. | 825 | 825 |
| Dividend receivable | 5 | 5 |
| Loans from affiliate company | | |
| IPL System Inc. | 375 | 375 |
| Interest payable | 9 | 2 |
| Note payable to affiliate company | | |
| Enbridge (U.S.) Inc. | 8 | 6 |
| Accounts receivables/(payables) | | |
| Enbridge Inc. | (1) | (1) |
| Gazifère Inc. | 4 | 5 |
| Niagara Gas Transmission Ltd. | 2 | - |

### Financing Transactions

The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2011, the investment of $825 million (2010 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2011, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

### Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

### Wholesale Service

These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

### Gas Transportation Services

The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2012 - $69 million, 2013 to 2014 - $131 million, 2015 to 2016 - $70 million and thereafter - nil.

### Information Services

The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

### Trade Receivables and Payables

The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

### Other Transactions

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 4)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

## 21. COMMITMENTS AND CONTINGENCIES

### Commitments

The Company has entered into long-term contracts and future payments under the contracts are as follows:

| | Total | Less than 1 year | 1-3 years | 3-5 years | After 5 years |
|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | |
| Services contract[1] | 15 | 7 | 8 | - | - |
| Customer care service contracts[2] | 359 | 58 | 115 | 122 | 64 |
| Total | 374 | 65 | 123 | 122 | 64 |

[1] *Primarily fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*

[2] *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

### Contingencies

#### Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

### Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

## Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## TRUSTEE AND REGISTRARS

### Debenture

9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

## REGISTRAR AND PAYING AGENT

### Medium Term Notes

Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

## TRUSTEE

### Medium Term Notes

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

## REGISTRAR AND TRANSFER AGENT

### Group 3 Preferred Shares

Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite

D.A. Leslie

J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2011), which is incorporated herein by reference.

ENBRIDGE

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2011 HISTORICAL YEAR

| Line no. | | Col. 1<br>Audited Consolidated Income<br>($millions) | Col. 2<br>Utility Income<br>($millions) | Col. 3<br>Difference<br>($millions) | Col. 4<br>Reference |
|---|---|---|---|---|---|
| 1. | Gas commodity and distribution revenue | 2,010.2 | 1,978.4 | (31.8) | a) |
| 2. | Transportation of gas for customers | 352.1 | 411.2 | 59.1 | b) |
| 3. | | 2,362.3 | 2,389.6 | 27.3 | |
| 4. | Gas commodity and distribution costs | 1,341.7 | 1,383.7 | 42.0 | c) |
| 5. | Gas distribution margin | 1,020.6 | 1,005.9 | (14.7) | |
| 6. | Other revenue | 104.4 | 42.9 | (61.5) | d) |
| 7. | | 1,125.0 | 1,048.8 | (76.2) | |
| | Expenses | | | | |
| 8. | Operation and maintenance | 418.8 | 360.5 | (58.3) | e) |
| 9. | Earnings sharing | 13.0 | - | (13.0) | f) |
| 10. | Depreciation | 281.0 | 276.6 | (4.4) | g) |
| 11. | Municipal and other taxes | 40.5 | 37.6 | (2.9) | h) |
| 12. | Company share of IR agreement tax savings | - | 22.3 | 22.3 | i) |
| 13. | | 753.3 | 697.0 | (56.3) | |
| 14. | Income before undernoted items | 371.7 | 351.8 | (19.9) | |
| 15. | Financing income | 62.7 | - | (62.7) | j) |
| 16. | Interest and financing expenses | (172.4) | (3.1) | 169.3 | k) |
| 17. | Income before income taxes | 262.0 | 348.7 | 86.7 | |
| 18. | Income taxes | 50.7 | 57.0 | 6.3 | l) |
| 19. | Net Income | 211.3 | 291.7 | 80.4 | |

Witness: K. Culbert

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

| Ref.s | Amount ($million) | Reclassification and elimination of revenue / expense items |
|---|---|---|
| a) | 2,010.2 | **Consolidated gas commodity and distribution revenue** |
| | (32.3) | Amounts related to St. Lawrence Gas |
| | (1.1) | Normalization adjustment |
| | 1.4 | Gazifere T-service regrouped to gas commodity and distribution revenue |
| | 0.2 | Remove adjustment relating to the updated tax saving sharing agreement included in the 2011 financials, but already reflected in the 2010 ESM calculation |
| | 1,978.4 | **Utility gas commodity and distribution revenue** |
| b) | 352.1 | **Consolidated transportation of gas for customers** |
| | (6.9) | Amounts related to St. Lawrence Gas |
| | (1.4) | Normalization adjustment |
| | (1.4) | Gazifere T-service regrouped to gas commodity and distribution revenue |
| | 68.8 | Western T-Service Credits regrouped to gas costs |
| | 411.2 | **Utility transportation of gas for customers** |
| c) | 1,341.7 | **Consolidated gas commodity and distribution costs** |
| | (25.7) | Elimination of amounts related to St. Lawrence Gas and unregulated storage |
| | (1.1) | Normalization adjustment |
| | 68.8 | Western T-Service Credits regrouped to gas costs |
| | 1,383.7 | **Utility gas commodity and distribution costs** |

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

| Ref.s | Amount ($million) | Reclassification and elimination of revenue / expense items |
|---|---|---|
| d) | 104.4 | **Consolidated other revenue** |
| | (21.5) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (13.6) | Open Bill O&M expenses regrouped against program revenues |
| | (5.1) | ABC administration and bad debt costs regrouped against program revenues from O&M |
| | (0.1) | ABC interest charges regrouped against program revenues |
| | 5.2 | Allowable interest during construction regrouped to revenues from interest and financing expenses |
| | (7.3) | Electric CDM costs regrouped against program revenues from O&M |
| | 0.1 | NGV program revenue imputation |
| | (4.4) | Elimination of transactional services revenue above base amount included in rates |
| | 0.2 | Elimination of the shareholder portion of the OBSDA and OBAVA write-off |
| | (0.2) | Elimination of the shareholder portion of net ex-franchise Open Bill revenues |
| | (1.6) | Elimination of Open Bill revenues to reflect the shareholder incentive |
| | (0.3) | Elimination of the shareholder portion of net electric CDM revenues |
| | (1.3) | Elimination of affiliate and 3rd party asset use revenue considered non-utility |
| | (5.9) | Elimination of net ABC revenue considered non-utility |
| | (0.5) | Elimination of interest income from investments not included in rate base |
| | (5.2) | Elimination of allowable interest during construction |
| | 42.9 | **Utility other revenue** |
| e) | 418.8 | **Consolidated operation and maintenance** |
| | (11.5) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (13.6) | Open Bill expenses regrouped against program revenues |
| | (5.1) | ABC administration and bad debt costs regrouped against program revenues and eliminated |
| | (7.3) | Electric CDM expenses regrouped against program revenues |
| | 1.0 | Interest on security deposits added to utility O&M |
| | (3.0) | Elimination of donations |
| | (1.8) | Elimination of non-utility costs of supporting the ABC program |
| | (16.7) | Elimination of Corporate Cost Allocations above RCAM amount |
| | (0.1) | Elimination of non-utility green energy costs |
| | (0.2) | Incremental unregulated storage allocation resulting from the incorporation of the B&V Study |
| | 360.5 | **Utility operation and maintenance** |
| f) | 13.0 | **Consolidated earnings sharing** |
| | (13.0) | Elimination of earnings sharing amounts within year end financials from utility income calculation |
| | - | **Utility earnings sharing** |
| g) | 281.0 | **Consolidated depreciation** |
| | (3.9) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (0.2) | Elimination of depreciation on disallowed Mississauga Southern Link |
| | (0.3) | Elimination of depreciation related to shared assets |
| | 276.6 | **Utility depreciation** |

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

| Ref.s | Amount ($million) | Reclassification and elimination of revenue / expense items |
|---|---|---|
| h) | 40.5 | **Consolidated municipal and other taxes** |
| | (1.7) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (0.2) | Elimination of municipal taxes related to shared assets |
| | (1.0) | Adjustment to convert capital taxes to a utility "stand-alone" basis |
| | 37.6 | **Utility municipal and other taxes** |
| i) | - | **Consolidated IR agreement tax savings** |
| | 22.3 | Recognition of the Company's share of IR agreement tax savings, as determined in EB-2007-0615, and updated in EB-2009-0172, EB-2010-0146, and EB-2011-0008. |
| | 22.3 | **Utility IR agreement tax savings** |
| j) | 62.7 | **Consolidated financing income** |
| | (62.7) | Eliminate non-utility dividend income from the Board Approved financing transaction |
| | - | **Utility financing income** |
| k) | 172.4 | **Consolidated interest and financing expenses** |
| | (2.5) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (26.8) | Eliminate non-utility interest expense from the Board Approved financing transaction |
| | 5.2 | Allowable interest during construction regrouped to revenues and eliminated |
| | (0.1) | ABC interest charges regrouped against program revenues and eliminated |
| | (145.1) | Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure |
| | 3.1 | **Utility interest and financing expenses** |
| l) | 50.7 | **Consolidated income taxes** |
| | (3.8) | Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects |
| | (46.9) | Elimination of corporate income taxes |
| | 57.0 | Addition of income taxes calculated on a utility "stand-alone" basis |
| | 57.0 | **Utility income taxes** |




# ENBRIDGE INC.

# CONSOLIDATED FINANCIAL STATEMENTS

## December 31, 2010

# MANAGEMENT'S REPORT

## To the Shareholders of Enbridge Inc.

**Financial Reporting**
Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

**Internal Control over Financial Reporting**
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2010.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).

"signed"
_____
**Patrick D. Daniel**
President & Chief Executive Officer

"signed"
_____
**J. Richard Bird**
Executive Vice President &
Chief Financial Officer

February 18, 2011

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
**Chartered Accountants**
111 5 Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 403 509 7500
Facsimile +1 403 781 1825
www.pwc.com/ca

**Independent Auditor's Report**

**To the Shareholders**
**of Enbridge Inc.**

We have completed integrated audits of Enbridge Inc.'s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

**Report on the consolidated financial statements**
We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

**Management's responsibility for the consolidated financial statements**
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's responsibility**
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

**Opinion**
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the three years in the period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

"PricewaterhouseCoopers" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership, or, as the context requires, the PricewaterhouseCoopers global network or other member firms of the network, each of which is a separate legal entity.

PRICEWATERHOUSECOOPERS

**Report on internal control over financial reporting**
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2010, based on the criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

**Management's responsibility for internal control over financial reporting**
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

**Auditor's responsibility**
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

**Definition of internal control over financial reporting**
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with Canadian generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

**Inherent limitations**
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

**Opinion**
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control - Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

**Chartered Accountants**
Calgary, Alberta, Canada

February 18, 2011

# CONSOLIDATED STATEMENTS OF EARNINGS

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Revenues | | | |
| Commodity sales | **11,990** | 9,720 | 13,432 |
| Transportation and other services | **3,137** | 2,746 | 2,699 |
| | **15,127** | 12,466 | 16,131 |
| Expenses | | | |
| Commodity costs | **11,291** | 9,011 | 12,792 |
| Operating and administrative | **1,466** | 1,430 | 1,312 |
| Depreciation and amortization | **864** | 764 | 658 |
| | **13,621** | 11,205 | 14,762 |
| | **1,506** | 1,261 | 1,369 |
| Income from Equity Investments | **38** | 198 | 177 |
| Other Income *(Note 28)* | **374** | 678 | 198 |
| Interest Expense *(Note 16)* | **(687)** | (597) | (551) |
| Gain on Sale of Investments *(Note 6)* | **-** | 365 | 700 |
| | **1,231** | 1,905 | 1,893 |
| Non-Controlling Interests | **(10)** | (37) | (56) |
| | **1,221** | 1,868 | 1,837 |
| Income Taxes *(Note 26)* | **(251)** | (306) | (509) |
| Earnings | **970** | 1,562 | 1,328 |
| Preferred Share Dividends | **(7)** | (7) | (7) |
| Earnings Applicable to Common Shareholders | **963** | 1,555 | 1,321 |
| Earnings per Common Share *(Note 20)* | **2.60** | 4.27 | 3.67 |
| Diluted Earnings per Common Share *(Note 20)* | **2.57** | 4.25 | 3.64 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings | **970** | 1,562 | 1,328 |
| Other Comprehensive Income/(Loss) | | | |
| Change in unrealized loss on cash flow hedges, net of tax | **(113)** | (54) | (127) |
| Change in unrealized gain/(loss) on net investment hedges, net of tax | **51** | 151 | (160) |
| Reclassification to earnings of realized cash flow hedges, net of tax | **(25)** | 114 | (1) |
| Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 6)* | **-** | (20) | - |
| Other comprehensive income/(loss) from equity investees, net of tax | **(11)** | (24) | 49 |
| Non-controlling interests in other comprehensive income/(loss) | **33** | 72 | (101) |
| Change in foreign currency translation adjustment | **(274)** | (815) | 658 |
| Other Comprehensive Income/(Loss) | **(339)** | (576) | 318 |
| Comprehensive Income | **631** | 986 | 1,646 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Preferred Shares *(Note 20)* | **125** | 125 | 125 |
| Common Shares *(Note 20)* | | | |
| Balance at beginning of year | **3,379** | 3,194 | 3,027 |
| Common shares issued | **-** | 4 | - |
| Dividend reinvestment and share purchase plan | **224** | 143 | 131 |
| Shares issued on exercise of stock options | **80** | 38 | 36 |
| Balance at End of Year | **3,683** | 3,379 | 3,194 |
| Contributed Surplus | | | |
| Balance at beginning of year | **54** | 38 | 26 |
| Stock-based compensation | **13** | 19 | 14 |
| Options exercised | **(8)** | (3) | (2) |
| Balance at End of Year | **59** | 54 | 38 |
| Retained Earnings | | | |
| Balance at beginning of year | **4,400** | 3,383 | 2,537 |
| Earnings applicable to common shareholders | **963** | 1,555 | 1,321 |
| Common share dividends declared | **(648)** | (555) | (489) |
| Dividends paid to reciprocal shareholder | **19** | 17 | 14 |
| Balance at End of Year | **4,734** | 4,400 | 3,383 |
| Accumulated Other Comprehensive Income/(Loss) *(Note 22)* | | | |
| Balance at beginning of year | **(543)** | 33 | (285) |
| Other comprehensive income/(loss) | **(339)** | (576) | 318 |
| Balance at End of Year | **(882)** | (543) | 33 |
| Reciprocal Shareholding *(Note 11)* | **(154)** | (154) | (154) |
| Total Shareholders' Equity | **7,565** | 7,261 | 6,619 |
| Dividends Paid per Common Share | **1.70** | 1.48 | 1.32 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Operating Activities** | | | |
| Earnings | **970** | 1,562 | 1,328 |
| Depreciation and amortization | **864** | 764 | 658 |
| Unrealized gains on derivative instruments | **(10)** | (204) | (120) |
| Allowance for equity funds used during construction | **(80)** | (135) | (59) |
| Cash distributions in excess of/(less than) equity earnings | **214** | (9) | (82) |
| Gain on reduction of ownership interest | **(81)** | - | (12) |
| Gain on sale of investments *(Note 6)* | **-** | (365) | (700) |
| Future income taxes | **238** | 218 | 258 |
| Goodwill and asset impairment losses | **-** | 11 | 23 |
| Non-controlling interests | **10** | 37 | 56 |
| Other | **(11)** | (105) | 48 |
| Changes in operating assets and liabilities *(Note 29)* | **(263)** | 243 | (26) |
| | **1,851** | 2,017 | 1,372 |
| **Investing Activities** | | | |
| Additions to property, plant and equipment | **(2,357)** | (3,225) | (3,545) |
| Additions to intangible assets | **(50)** | (95) | (91) |
| Change in construction payable | **27** | (110) | 106 |
| Long-term investments | **(121)** | (359) | (659) |
| Affiliate loans, net | **(80)** | (145) | - |
| Acquisitions *(Notes 10 and 19)* | **(116)** | - | - |
| Proceeds on sale of investments *(Note 6)* | **23** | 535 | 1,383 |
| Sale of property, plant and equipment | **-** | 87 | - |
| Settlement of hedges *(Note 6)* | **-** | 6 | (47) |
| | **(2,674)** | (3,306) | (2,853) |
| **Financing Activities** | | | |
| Net change in short-term borrowings | **(182)** | (366) | 329 |
| Net change in commercial paper and credit facility draws | **(347)** | 736 | 744 |
| Debenture and term note issues | **2,300** | 1,500 | 498 |
| Debenture and term note repayments | **(600)** | (616) | (602) |
| Net change in Southern Lights project financing | **14** | 343 | 1,238 |
| Non-recourse debt issues | **5** | 60 | 46 |
| Non-recourse debt repayments | **(73)** | (130) | (66) |
| Distributions to non-controlling interests, net | **(1)** | (33) | (10) |
| Common shares issued | **66** | 36 | 29 |
| Preferred share dividends | **(7)** | (7) | (7) |
| Common share dividends | **(426)** | (414) | (359) |
| | **749** | 1,109 | 1,840 |
| Effect of translation of foreign denominated cash and cash equivalents | **(11)** | (35) | 16 |
| Increase/(Decrease) in Cash and Cash Equivalents | **(85)** | (215) | 375 |
| Cash and Cash Equivalents at Beginning of Year | **327** | 542 | 167 |
| **Cash and Cash Equivalents at End of Year**[1] | **242** | 327 | 542 |
| **Supplementary Cash Flow Information** | | | |
| Income taxes paid *(Note 26)* | **108** | 205 | 161 |
| Interest paid *(Note 16)* | **711** | 656 | 607 |

*The accompanying notes are an integral part of these consolidated financial statements.*

1 *Cash and cash equivalents consists of $143 million (2009 - $184 million; 2008 - $68 million) of cash and $99 million (2009 - $143 million; 2008 - $474 million) of short-term investments and includes restricted cash of $12 million (2009 - $7 million; 2008 - $24 million), and joint-venture cash which is not readily accessible by the Company of $48 million (2009 - $52 million; 2008 - $57 million).*

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Assets** | | |
| Current Assets | | |
| Cash and cash equivalents | **242** | 327 |
| Accounts receivable and other *(Note 7)* | **2,706** | 2,484 |
| Inventory *(Note 8)* | **813** | 784 |
| | **3,761** | 3,595 |
| Property, Plant and Equipment, net *(Note 9)* | **20,332** | 18,850 |
| Long-Term Investments *(Note 11)* | **2,198** | 2,312 |
| Deferred Amounts and Other Assets *(Note 12)* | **2,886** | 2,425 |
| Intangible Assets *(Note 13)* | **478** | 488 |
| Goodwill *(Note 14)* | **385** | 372 |
| Future Income Taxes *(Note 26)* | **80** | 127 |
| | **30,120** | 28,169 |
| **Liabilities and Shareholders' Equity** | | |
| Current Liabilities | | |
| Short-term borrowings *(Note 16)* | **326** | 508 |
| Accounts payable and other *(Note 15)* | **2,688** | 2,463 |
| Interest payable | **117** | 104 |
| Current maturities of long-term debt *(Note 16)* | **154** | 601 |
| Current maturities of non-recourse long-term debt *(Note 17)* | **70** | 113 |
| | **3,355** | 3,789 |
| Long-Term Debt *(Note 16)* | **13,561** | 11,866 |
| Non-Recourse Long-Term Debt *(Note 17)* | **1,061** | 1,108 |
| Other Long-Term Liabilities *(Note 18)* | **1,473** | 1,207 |
| Future Income Taxes *(Note 26)* | **2,447** | 2,211 |
| | **21,897** | 20,181 |
| Non-Controlling Interests *(Note 19)* | **658** | 727 |
| Shareholders' Equity | | |
| Share capital | | |
| Preferred shares *(Note 20)* | **125** | 125 |
| Common shares *(Note 20)* | **3,683** | 3,379 |
| Contributed surplus | **59** | 54 |
| Retained earnings | **4,734** | 4,400 |
| Accumulated other comprehensive loss *(Note 22)* | **(882)** | (543) |
| Reciprocal shareholding *(Note 11)* | **(154)** | (154) |
| | **7,565** | 7,261 |
| Commitments and Contingencies *(Note 31)* | | |
| | **30,120** | 28,169 |

*The accompanying notes are an integral part of these consolidated financial statements.*

Approved by the Board of Directors:

"signed"

**David A. Arledge**
Chair

"signed"

**David A. Leslie**
Director

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

## 1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments, and Corporate. These operating segments have been revised to better reflect the strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance. Segmented information has been retroactively reclassified to reflect these changes, but had no impact on reported Consolidated Earnings Applicable to Common Shareholders.

**LIQUIDS PIPELINES**

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States, including the Enbridge System, the Enbridge Regional Oil Sands System, Southern Lights Pipeline and other feeder pipelines.

**GAS DISTRIBUTION**

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

**GAS PIPELINES, PROCESSING AND ENERGY SERVICES**

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, processing and green energy projects, the Company's commodity marketing businesses, and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in processing includes the Company's interest in Aux Sable, a natural gas fractionation and extraction business. The commodity marketing businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform commodity storage, transport and supply management services, as principal and agent.

**SPONSORED INVESTMENTS**

Sponsored Investments includes the Company's 25.5% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, L.P. (EELP) and an overall 72% economic interest in Enbridge Income Fund (EIF), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (EIFH). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of EIF include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline Canada and partial interests in several green energy investments.

**CORPORATE**

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, general corporate investments and financing costs not allocated to the business segments.

# 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post employment benefits *(Note 27)*; commitments and contingencies *(Note 31);* and fair value of asset retirement obligations. Actual results could differ from these estimates.

**BASIS OF PRESENTATION**

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of various joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through the combination of a total direct and indirect 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to Maturity, Loans and Receivables or Available for Sale (see Financial Instruments).

**REGULATION**

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta (ERCB), the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are included in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

**REVENUE RECOGNITION**
For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For rate-regulated operations in Sponsored Investments and in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

**FINANCIAL INSTRUMENTS**
The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the consolidated statement of financial position. Subsequent measurement of the financial instrument is based on its classification.

**Held for Trading**
Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Commodity Costs, Other Income and Interest Expense. The Company has classified Cash and Cash Equivalents and its non-qualifying derivative instruments as held for trading.

**Available for Sale**
Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other Comprehensive Income/(Loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from Available for Sale financial assets are recognized in earnings when the right to receive payment is established.

**Loans and Receivables**
Loans and receivables, which include Accounts Receivable and Other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

**Held to Maturity**
The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

**Other Financial Liabilities**
Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term Borrowings, Accounts Payable and Other, Interest Payable, Long-term Debt and Non-recourse Long-term Debt.

**Derivatives in Qualifying Hedging Relationships**
The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

**Cash Flow Hedges**
The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

**Fair Value Hedges**
The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

**Net Investment Hedges**
The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated Other Comprehensive Income/(Loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a disposal of the foreign operation.

**Balance Sheet Offset**
Assets and liabilities arising from derivative instruments are offset in the Consolidated Statement of Financial Position when the Company has the legal right and intention to settle them on a net basis.

**Impairment**
With respect to available for sale instruments, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of

impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to loans and receivables, the Company assesses the assets for impairment when it no longer has a reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the loan or receivable to its estimated realizable amount, determined using discounted expected future cash flows.

**Transaction Costs**
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

**INCOME TAXES**
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a future income tax liability is recognized with a corresponding regulatory asset.

**FOREIGN CURRENCY TRANSLATION**
The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these operations are included in the foreign currency translation adjustment component of AOCI.

Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statement of Earnings in the period that they arise.

**CASH AND CASH EQUIVALENTS**
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

**INVENTORY**
Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

**PROPERTY, PLANT AND EQUIPMENT**
Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate-regulated assets, if approved, an allowance for equity funds used during construction (AEDC) is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment

is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

**IMPAIRMENT OF LONG-LIVED ASSETS**
The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

**DEFERRED AMOUNTS AND OTHER ASSETS**
Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

**INTANGIBLE ASSETS**
Intangible assets consist primarily of acquired long-term transportation contracts and software costs, which are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

**GOODWILL**
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

**ASSET RETIREMENT OBLIGATIONS**
Asset retirement obligations (AROs) associated with the retirement of long-lived assets are measured at fair value and recognized as Other Long-term Liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

**POST-EMPLOYMENT BENEFITS**
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;

- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

**STOCK BASED COMPENSATION**
Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units (RSUs) vest at the completion of a 35-month term. Both PSUs and RSUs are settled in cash. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts Payable and Other or Other Long-Term Liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

**COMPARATIVE AMOUNTS**
Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

## 3. CHANGES IN ACCOUNTING POLICIES

**FUTURE ACCOUNTING POLICY CHANGES**
**International Financial Reporting Standards**
First-time adoption of Part I - International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V - Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

**Business Combinations**
CICA Handbook Section 1582, *Business Combinations,* replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair

value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of future business combinations occurring on or after January 1, 2011.

**Consolidated Financial Statements and Non-Controlling Interests**
The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards impacts presentation only. They are not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

# 4. SEGMENTED INFORMATION

| **Year ended December 31, 2010** | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | **1,672** | **2,611** | **10,518** | **326** | **-** | **15,127** |
| Commodity costs | **-** | **(1,384)** | **(9,907)** | **-** | **-** | **(11,291)** |
| Operating and administrative | **(603)** | **(497)** | **(215)** | **(120)** | **(31)** | **(1,466)** |
| Depreciation and amortization | **(312)** | **(310)** | **(144)** | **(88)** | **(10)** | **(864)** |
| | **757** | **420** | **252** | **118** | **(41)** | **1,506** |
| Income from equity investments | **-** | **-** | **-** | **32** | **6** | **38** |
| Other income/(expense) and gain on sale of investments | **115** | **(17)** | **30** | **114** | **132** | **374** |
| Interest and preferred share dividends | **(223)** | **(179)** | **(96)** | **(58)** | **(138)** | **(694)** |
| Non-controlling interest | **(2)** | **(5)** | **-** | **(3)** | **-** | **(10)** |
| Income taxes | **(135)** | **(64)** | **(65)** | **(66)** | **79** | **(251)** |
| Earnings applicable to common shareholders | **512** | **155** | **121** | **137** | **38** | **963** |

| Year ended December 31, 2009 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | 1,333 | 2,992 | 7,823 | 313 | 5 | 12,466 |
| Commodity costs | - | (1,757) | (7,254) | - | - | (9,011) |
| Operating and administrative | (565) | (495) | (226) | (113) | (31) | (1,430) |
| Depreciation and amortization | (230) | (298) | (140) | (88) | (8) | (764) |
| | 538 | 442 | 203 | 112 | (34) | 1,261 |
| Income from equity investments | - | - | - | 188 | 10 | 198 |
| Other income/(expense) and gain on sale of investments | 161 | (12) | 366 | 13 | 515 | 1,043 |
| Interest and preferred share dividends | (144) | (188) | (87) | (56) | (129) | (604) |
| Non-controlling interests | (2) | (6) | - | (28) | (1) | (37) |
| Income taxes | (108) | (50) | (54) | (88) | (6) | (306) |
| Earnings applicable to common shareholders | 445 | 186 | 428 | 141 | 355 | 1,555 |

| Year ended December 31, 2008 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | 1,170 | 3,189 | 11,464 | 298 | 10 | 16,131 |
| Commodity costs | - | (1,994) | (10,798) | - | - | (12,792) |
| Operating and administrative | (492) | (475) | (211) | (102) | (32) | (1,312) |
| Depreciation and amortization | (181) | (277) | (115) | (78) | (7) | (658) |
| | 497 | 443 | 340 | 118 | (29) | 1,369 |
| Income from equity investments | - | - | 25 | 148 | 4 | 177 |
| Other income and gain on sale of investments | 61 | 14 | 718 | 25 | 80 | 898 |
| Interest and preferred share dividends | (111) | (193) | (77) | (60) | (117) | (558) |
| Non-controlling interests | (1) | (7) | - | (47) | (1) | (56) |
| Income taxes | (118) | (96) | (239) | (73) | 17 | (509) |
| Earnings applicable to common shareholders | 328 | 161 | 767 | 111 | (46) | 1,321 |

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

**TOTAL ASSETS**

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Liquids Pipelines | **11,503** | 10,763 |
| Gas Distribution | **7,562** | 7,377 |
| Gas Pipelines, Processing and Energy Services | **5,533** | 4,801 |
| Sponsored Investments | **3,822** | 3,860 |
| Corporate | **1,700** | 1,368 |
| | **30,120** | 28,169 |

**ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT**[1]

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Liquids Pipelines | **765** | 2,662 |
| Gas Distribution | **387** | 326 |
| Gas Pipelines, Processing and Energy Services | **1,153** | 321 |
| Sponsored Investments | **132** | 41 |
| Corporate | **-** | 10 |
| | **2,437** | 3,360 |

*1 Includes AEDC.*

**GEOGRAPHIC INFORMATION**

**Revenues**[1]

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Canada | **9,876** | 9,503 | 12,459 |
| United States | **5,251** | 2,963 | 3,672 |
| | **15,127** | 12,466 | 16,131 |

*1 Revenues are based on the country of origin of the product or services sold.*

**Property, Plant and Equipment**

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canada | **16,095** | 15,101 |
| United States | **4,237** | 3,749 |
| | **20,332** | 18,850 |

# 5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

**GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS**

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

**Enbridge System**

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are based on a cost of service methodology and are based on agreements with customers which are filed with the NEB for approval.

The incentive tolling settlement (ITS) was effective from 2005 to 2009 and a one year ITS was approved by the NEB for 2010. The Company has reached agreement with industry to roll forward the 2010 ITS agreement for a year and will file the 2011 ITS with the NEB in March 2011. The ITS defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval. Surcharges are also determined for a number of system expansion components and are added to the base toll determined for the core system. Discussions with industry continue for a longer term settlement agreement which will support a competitive toll structure. Until all matters before the NEB are settled, interim tolls will continue to be collected for the Enbridge System.

**Southern Lights**

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

**Enbridge Gas Distribution**

EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation (IR) methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2010, 2009 and 2008 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

**Enbridge Gas New Brunswick**

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE for the year ended December 31, 2010 was 13.00% (2009 - 13.00%; 2008 - 13.00%) based on equity which is capped at 50%.

**Vector Pipeline**
Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2010 included an after tax ROE component of 11.18% (2009 - 11.07%; 2008 - 11.04%).

**Alliance Pipeline**
The United States portion of the Alliance Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Alliance Pipeline are subject to 15-year transportation contracts that expire in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2010, 2009 and 2008 included an after tax ROE component of 10.88% for the United States portion and 11.26% for the Canadian portion. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

**FINANCIAL STATEMENT EFFECTS**
Accounting for rate-regulated entities has resulted in the recognition of the following significant regulatory assets and liabilities:

| December 31, | **2010** | 2009 | Estimated Settlement Period (years) | Earnings Impact[1] **2010** | 2009 | 2008 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Regulatory Assets/(Liabilities)** | | | | | | |
| Liquids Pipelines | | | | | | |
| Future income taxes[2] | **575** | 504 | - | **53** | 49 | - |
| Tolling deferrals[3] | **91** | 98 | 1 | **(7)** | (16) | (30) |
| Gas Distribution | | | | | | |
| Future income taxes[2] | **169** | 227 | - | **(7)** | (11) | - |
| EGNB regulatory deferral[4] | **171** | 155 | 30 | **18** | 15 | 10 |
| Future removal and site restoration reserves[5] | **(773)** | (710) | - | - | 6 | - |
| Purchased gas variance[6] | **(144)** | (227) | 1 | - | - | - |
| Pension plans and OPEB, net[7] | **(114)** | (60) | - | - | (2) | - |
| Gas Pipelines, Processing and Energy Services | | | | | | |
| Future income taxes[2] | **42** | - | - | **(5)** | - | - |
| Deferred transportation revenue[8] | **150** | 185 | 13-15 | **(17)** | (6) | 1 |
| Sponsored Investments | | | | | | |
| Future income taxes[2] | **94** | 98 | - | **(3)** | (11) | - |
| Deferred transportation revenue[8] | **98** | 91 | 15 | **5** | 5 | 6 |

*1 The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

*2 This regulatory asset is a corresponding balance to a future income tax liability, first recognized on adoption of the revised CICA Handbook section 3465 – Income Taxes in 2009.The asset represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

*3 Tolls are calculated in accordance with the ITS, System Expansion Program (SEP), Terrace, Southern Access, Line 4, Alberta Clipper and Southern Lights Pipeline agreements and are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a regulatory asset is recognized and incorporated into tolls in the subsequent year. Recovery in the subsequent year, in whole or*

*in part, is dependent upon realizing shipping volumes consistent with tolling model forecasts. Under or over collections are included in subsequent years' tolls. In addition, other tolling deferrals are recorded in accordance with the various agreements.*

4 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end in 2043.*

5 *The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company's businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

6 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity sales would be adjusted by an equal and corresponding amount as the right to collect revenue has been established.*

7 *The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The other post employment benefits (OPEB) balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

8 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.*

**OTHER ITEMS AFFECTED BY RATE REGULATION**

**Allowance for Funds Used During Construction and Other Capitalized Costs**

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

**Operating Cost Capitalization**

With the approval of the OEB, EGD capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2010, cumulative costs relating to this consulting contract of $124 million (2009 - $112 million) were included in property plant and equipment, and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

## 6. GAIN ON SALE OF INVESTMENTS

| December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| NetThruPut (NTP) | **-** | 29 | - |
| Oleoducto Central S.A. (OCENSA) | **-** | 336 | - |
| Compañía Logística de Hidrocarburos CLH, S.A. (CLH) | **-** | - | 695 |
| Other | **-** | - | 5 |
| | **-** | 365 | 700 |

**NTP**
On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million (2008 - $1 million) and are included in the Corporate operating segment.

**OCENSA**
On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million (2008 - $33 million). Earnings from the OCENSA investment are included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

**CLH**
On June 17, 2008, the Company sold its 25% investment in CLH for total proceeds of $1,380 million (€876 million), net of transaction costs. The sale of CLH resulted in a gain of $695 million. Earnings generated by the CLH investment for the year ended December 31, 2008 were $25 million and are included in the Gas Pipelines, Processing and Energy Services operating segment. Operating cash flows generated by the CLH investment for the year ended December 31, 2008 were $12 million.

## 7. ACCOUNTS RECEIVABLE AND OTHER

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Unbilled revenues | **1,284** | 1,018 |
| Trade receivables | **740** | 681 |
| Taxes receivable | **205** | 94 |
| Regulatory assets | **182** | 181 |
| Current derivative assets *(Note 23)* | **170** | 128 |
| Due from affiliates *(Note 30)* | **63** | 336 |
| Prepaid expenses and deposits | **36** | 27 |
| Dividends receivable | **16** | 14 |
| Other | **72** | 79 |
| Allowance for doubtful accounts *(Note 23)* | **(62)** | (74) |
| | **2,706** | 2,484 |

## 8. INVENTORY

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Natural gas | **537** | 492 |
| Other commodities | **276** | 292 |
| | **813** | 784 |

# 9. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2010 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | | | | |
| Pipeline | **2.7%** | **7,295** | **1,618** | **5,677** |
| Pumping equipment, buildings, tanks and other | **3.6%** | **4,728** | **1,221** | **3,507** |
| Land and right-of-way | **1.8%** | **232** | **29** | **203** |
| Under construction | **-** | **728** | **-** | **728** |
| | | **12,983** | **2,868** | **10,115** |
| Gas Distribution | | | | |
| Pipeline | **2.3%** | **29** | **10** | **19** |
| Gas mains, services and other | **3.6%** | **6,576** | **1,262** | **5,314** |
| Land and right-of-way | **2.6%** | **68** | **15** | **53** |
| Under construction | **-** | **103** | **-** | **103** |
| | | **6,776** | **1,287** | **5,489** |
| Gas Pipelines, Processing and Energy Services | | | | |
| Pipeline | **3.4%** | **2,121** | **706** | **1,415** |
| Wind turbines, solar panels and other | **3.1%** | **1,527** | **142** | **1,385** |
| Land and right-of-way | **2.4%** | **62** | **13** | **49** |
| Under construction | **-** | **622** | **-** | **622** |
| | | **4,332** | **861** | **3,471** |
| Sponsored Investments | | | | |
| Pipeline | **4.0%** | **1,598** | **484** | **1,114** |
| Other | **8.5%** | **108** | **29** | **79** |
| Under construction | **-** | **17** | **-** | **17** |
| | | **1,723** | **513** | **1,210** |
| Corporate | | | | |
| Other | **11.3%** | **67** | **20** | **47** |
| | | **67** | **20** | **47** |
| | | **25,881** | **5,549** | **20,332** |

| December 31, 2009 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | | | | |
| Pipeline | 2.4% | 4,053 | 1,481 | 2,572 |
| Pumping equipment, buildings, tanks and other | 3.5% | 4,029 | 1,065 | 2,964 |
| Land and right-of-way | 2.0% | 118 | 23 | 95 |
| Under construction | - | 4,129 | - | 4,129 |
| | | 12,329 | 2,569 | 9,760 |
| Gas Distribution | | | | |
| Pipeline | 2.3% | 21 | 5 | 16 |
| Gas mains, services and other | 3.8% | 6,122 | 982 | 5,140 |
| Land and right-of-way | 5.0% | 49 | 8 | 41 |
| Under construction | - | 111 | - | 111 |
| | | 6,303 | 995 | 5,308 |
| Gas Pipelines, Processing and Energy Services | | | | |
| Pipeline | 3.4% | 2,104 | 679 | 1,425 |
| Wind turbines, solar panels and other | 3.8% | 890 | 108 | 782 |
| Land and right-of-way | 2.9% | 48 | 13 | 35 |
| Under construction | - | 321 | - | 321 |
| | | 3,363 | 800 | 2,563 |
| Sponsored Investments | | | | |
| Pipeline | 4.6% | 1,406 | 368 | 1,038 |
| Other | 6.9% | 108 | 18 | 90 |
| Under construction | - | 31 | - | 31 |
| | | 1,545 | 386 | 1,159 |
| Corporate | | | | |
| Other | 11.3% | 77 | 17 | 60 |
| | | 77 | 17 | 60 |
| | | 23,617 | 4,767 | 18,850 |

## 10. JOINT VENTURES

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

| | Ownership | Net Assets | |
|---|---|---|---|
| December 31, | Interest | **2010** | 2009 |
| *(millions of Canadian dollars)* | | | |
| Liquids Pipelines | | | |
| Chicap Pipeline | 43.8% | **27** | 9 |
| Mustang Pipeline | 30% | **26** | 22 |
| Olympic Pipeline | 85% (2009 - 65%) | **-** | 111 |
| Hardisty Caverns | 100% (2009 - 50%) | **-** | 33 |
| Gas Pipelines, Processing and Energy Services | | | |
| Enbridge Offshore Pipelines - various joint ventures | 22%-74.3% | **433** | 385 |
| Vector Pipeline | 60% | **349** | 420 |
| Alliance Pipeline US | 50% | **318** | 383 |
| Aux Sable | 42.7%-50% | **86** | 153 |
| Other | 33.3%-70% | **50** | 32 |
| Sponsored Investments | | | |
| Alliance Pipeline Canada | 50% | **660** | 676 |
| Other | 33%-50% | **56** | 46 |
| | | **2,005** | 2,270 |

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings | | | |
| Revenues | **771** | 781 | 891 |
| Commodity costs | **(92)** | (74) | (174) |
| Operating and administrative | **(203)** | (226) | (235) |
| Depreciation and amortization | **(163)** | (171) | (173) |
| Interest expense | **(82)** | (99) | (97) |
| Other income/(expense) | **(1)** | 10 | 13 |
| Proportionate share of earnings | **230** | 221 | 225 |
| Cash Flows | | | |
| Cash provided by operating activities | **349** | 342 | 408 |
| Cash used in investing activities | **(57)** | (49) | (61) |
| Cash used in financing activities | **(78)** | (133) | (121) |
| Proportionate share of increase in cash and cash equivalents | **214** | 160 | 226 |

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Financial Position | | |
| Current assets | **171** | 173 |
| Property, plant and equipment, net | **2,331** | 2,657 |
| Intangible assets | **166** | 188 |
| Goodwill | **321** | 321 |
| Deferred amounts and other assets | **270** | 299 |
| Current liabilities | **(150)** | (212) |
| Non-recourse long-term debt | **(1,061)** | (1,108) |
| Other long-term liabilities | **(43)** | (48) |
| Proportionate share of net assets | **2,005** | 2,270 |

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipeline Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

During the year ended December 31, 2008, the Company purchased an additional equity interest in Chicap Pipeline Company (Chicap Pipeline), increasing its ownership percentage to 43.8%. As the Company established joint control over the entity effective October 31, 2008, it has proportionally consolidated its interest in Chicap Pipeline from that date forward. Prior to October 31, 2008, the entity was classified as a long-term investment.

# 11. LONG-TERM INVESTMENTS

| December 31, | Ownership Interest | **2010** | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Equity Investments** | | | |
| Sponsored Investments | | | |
| The Partnership | 25.5% | **1,473** | 1,697 |
| Enbridge Energy, L.P. - Series AC | 66.7% | **463** | 357 |
| Corporate | | | |
| Noverco Inc. Common Shares | 32.1% | **14** | 14 |
| Other | 5%-14% | **13** | 9 |
| **Other Investments** | | | |
| Corporate | | | |
| Noverco Inc. Preferred Shares | | **181** | 181 |
| Value Creation Inc. | | **29** | 29 |
| Fuel Cell Energy Ltd. | | **25** | 25 |
| | | **2,198** | 2,312 |

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $123 million at December 31, 2010 (2009 - $126 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

**The Partnership**
The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 25.5% ownership in EEP, through a 2.0% general partner interest, an 18.1% interest in Class A units, a 3.0% interest in Class B units and a 2.4% interest in EEP as a result of a 17.2% investment in EEM, which owns 13.7% of EEP through its 100% interest in EEP's i-units. The Company recorded investment income of $51 million (2009 - $175 million; 2008 - $162 million), inclusive of incentive earnings, and including dilution gains of $81 million (2009 - nil; 2008 - $12 million), before tax and non-controlling interest, from EEP for the year ended December 31, 2010.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million, before tax and non-controlling interest, was recognized and Enbridge's ownership interest in EEP decreased from 27.0% to 25.5%.

Although 82.8% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

In October 2009, the Company converted its investment in EEP Class C units into Class A common units. The Class C units converted on a one-for-one basis, resulting in the issuance and receipt of 21,333,273 Class A common units. Prior to the unit conversion, distributions were paid in additional Class C units where Class C units were valued at the market value of Class A units.

In March 2008, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $12 million, before tax and non-controlling interest, was recognized and Enbridge's ownership interest in EEP decreased from 15.1% to 14.6%. In November 2008, the Company subscribed for 16.3 million Class A common units of EEP for US$510 million increasing its ownership interest from 14.6% to 27.0%.

**Enbridge Energy, L.P.**
The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project (*Note 30*). The Company recorded investment income from EELP of $63 million for the year ended December 31, 2010 (2009 - $12 million).

During 2010, the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $40 million (US$39 million) payable to the Company relating to its series AC interest in the Alberta Clipper project.

**Noverco**
The Company owns a preferred share investment in Noverco of $181 million at December 31, 2010 and 2009, which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%.

The Company also owns an equity investment in the common shares of Noverco of $14 million at December 31, 2010 (2009 - $14 million). Noverco owns an approximate 9.0% (2009 - 9.2%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 2.9% (2009 - 2.9%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $154 million at December 31, 2010 and 2009. Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2010, the Company recorded equity investment earnings of $6 million (2009 - $10 million; 2008 - $4 million) related to its interest in Noverco.

Subsequent to December 31, 2010, the Company announced that it will invest $145 million to acquire an additional 6.8% interest in Noverco, bringing its total investment in Noverco to 38.9%.

## 12. DEFERRED AMOUNTS AND OTHER ASSETS

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory assets | **1,514** | 1,419 |
| Long-term portion of derivative assets *(Note 23)* | **462** | 485 |
| Affiliate long-term note receivable *(Note 30)* | **334** | - |
| Pension asset *(Note 27)* | **301** | 216 |
| Contractual receivables | **182** | 171 |
| Other | **93** | 134 |
| | **2,886** | 2,425 |

At December 31, 2010, deferred amounts of $66 million (2009 - $71 million) were subject to amortization and are presented net of accumulated amortization of $39 million (2009 - $34 million). Amortization expense in 2010 was $9 million (2009 - $7 million; 2008 - $5 million).

## 13. INTANGIBLE ASSETS

| **December 31, 2010** | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | **13.4%** | **457** | **172** | **285** |
| Transportation agreements | **4.2%** | **231** | **66** | **165** |
| Power purchase agreements and other | **5.0%** | **33** | **5** | **28** |
| | | **721** | **243** | **478** |

| December 31, 2009 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | 17.1% | 448 | 159 | 289 |
| Transportation agreements | 4.2% | 232 | 56 | 176 |
| Power purchase agreements and other | 5.0% | 27 | 4 | 23 |
| | | 707 | 219 | 488 |

Total amortization expense for intangible assets was $60 million for the year ended December 31, 2010 (2009 - $44 million; 2008 - $58 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2011 through 2015 of $47 million, $41 million, $36 million, $32 million and $28 million, respectively.

## 14. GOODWILL

| | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at December 31, 2008 | 22 | - | 59 | 308 | - | 389 |
| Goodwill impairment | - | - | (7) | - | - | (7) |
| Foreign exchange and other | (3) | - | (7) | - | - | (10) |
| Balance at December 31, 2009 | 19 | - | 45 | 308 | - | 372 |
| Foreign exchange and other | **(1)** | **-** | **(3)** | **-** | **-** | **(4)** |
| Business acquisition | **17** | **-** | **-** | **-** | **-** | **17** |
| Balance at December 31, 2010 | **35** | **-** | **42** | **308** | **-** | **385** |

In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns. In 2009, the Company recognized an impairment of $7 million on goodwill related to Enbridge Electric Connections Inc.

## 15. ACCOUNTS PAYABLE AND OTHER

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Operating accrued liabilities | **1,621** | 1,313 |
| Trade payables | **232** | 415 |
| Construction payables | **253** | 163 |
| Taxes payable | **156** | 103 |
| Current derivative liabilities *(Note23)* | **138** | 123 |
| Security deposits | **78** | 60 |
| Contractor holdbacks | **78** | 108 |
| Other | **132** | 178 |
| | **2,688** | 2,463 |

## 16. DEBT

| December 31, | Weighted Average Interest Rate | Maturity | **2010** | 2009 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | | | | |
| Debentures | 8.20% | 2024 | **200** | 200 |
| Medium-term notes | 5.05% | 2012-2040 | **2,425** | 1,525 |
| Southern Lights project financing[1] | 2.54% | 2012-2014 | **1,488** | 1,531 |
| Commercial paper and credit facility draws, net[2] | | | **36** | 874 |
| Other[3] | | | **15** | 15 |
| Gas Distribution | | | | |
| Debentures | 10.46% | 2011-2024 | **235** | 385 |
| Medium-term notes | 5.54% | 2014-2050 | **2,195** | 1,795 |
| Commercial paper and credit facility draws, net | | | **334** | 512 |
| Sponsored Investments | | | | |
| Medium-term notes | 5.03% | 2014-2020 | **290** | 90 |
| Credit facility draws, net | | | **130** | 197 |
| Corporate | | | | |
| U.S. dollar term notes[4] | 5.48% | 2014-2017 | **1,094** | 1,151 |
| Medium-term notes | 5.25% | 2013-2040 | **2,918** | 2,568 |
| Commercial paper and credit facility draws, net[5] | | | **2,776** | 2,235 |
| Deferred debt issue costs and other | | | **(95)** | (103) |
| Total Debt | | | **14,041** | 12,975 |
| Current Maturities | | | **(154)** | (601) |
| Short-Term Borrowings | 1.14% | | **(326)** | (508) |
| Long-Term Debt | | | **13,561** | 11,866 |

*1 2010 - $388 million and US$1,106 million (2009 - $385 million and US$1,095 million).*

*2 2010 - $26 million and US$10 million (2009 - $874 million).*

*3 Primarily capital lease obligations.*

*4 2010 - US$1,100 (2009 - US$1,100).*

*5 2010 - $2,515 million and US$265 million (2009 - $1,973 million and US$250 million).*

Debenture and term note maturities for the years ending December 31, 2011 through 2015 are $154 million, $250 million, $201 million, $889 million and $549 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2011 through 2015 are $511 million, $504 million, $487 million, $466 million and $426 million, respectively.

**INTEREST EXPENSE**

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Debentures and term notes | **578** | 494 | 417 |
| Non-recourse long-term debt *(Note 17)* | **75** | 83 | 87 |
| Commercial paper and credit facility draws | **63** | 71 | 100 |
| Southern Lights project financing | **37** | 45 | 28 |
| Capitalized | **(66)** | (96) | (81) |
| | **687** | 597 | 551 |

**CREDIT FACILITIES**

| **December 31, 2010** | Expiry Dates[2] | Total Facilities | Credit Facility Draws[3] | Available |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | 2012 | 200 | 26 | 174 |
| Gas Distribution | 2011-2012 | 717 | 334 | 383 |
| Sponsored Investments | 2012 | 300 | 130 | 170 |
| Corporate | 2012-2014 | 4,631 | 2,826 | 1,805 |
| | | 5,848 | 3,316 | 2,532 |
| Southern Lights project financing[1] | 2012-2014 | 1,697 | 1,504 | 193 |
| Total Credit Facilities | | 7,545 | 4,820 | 2,725 |

*1 Total facilities inclusive of $60 million for debt service reserve letters of credit.*

*2 Includes $30 million in demand facilities with no maturity date.*

*3 Includes facility draws, letters of credit and commercial paper issuances, that are backstopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.20% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2011 to 2014.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,950 million (2009 - $3,310 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

## 17. NON–RECOURSE DEBT

| December 31, | Weighted Average Interest Rate | Maturity | **2010** | 2009 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Gas Pipelines, Processing and Energy Services | | | | |
| Long-term credit facilities[1] | | 2012 | **1** | 1 |
| Senior notes[2] | 6.79% | 2015-2025 | **347** | 400 |
| Term debt[3] | 3.81% | 2011-2019 | **29** | 24 |
| Capital lease obligations | 11.27% | 2020 | **32** | 36 |
| Sponsored Investments | | | | |
| Credit facilities | | 2012 | **23** | 25 |
| Senior notes | 6.68% | 2015-2025 | **675** | 708 |
| Fair value increment on senior notes acquired | | | **29** | 33 |
| Deferred debt issue costs and other | | | **(5)** | (6) |
| Total Non-Recourse Debt | | | **1,131** | 1,221 |
| Current Maturities | | | **(70)** | (113) |
| Non-Recourse Long-Term Debt | | | **1,061** | 1,108 |

*1 2010 - US$1 million (2009 - US$1 million).*

*2 2010 - US$349 million (2009 - US$382 million).*

*3 2010 - US$24 million (2009 - US$23 million).*

Maturities on non-recourse borrowings for the years ending December 31, 2011 through 2015 are $70 million, $94 million, $77 million, $80 million and $80 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2011 through 2015 are $71 million, $66 million, $61 million, $56 million and $50 million, respectively.

Certain assets of Alliance Pipeline Canada, with a carrying value of $1,006 million, are pledged as collateral to Alliance Pipeline Canada's lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US, with a carrying value of $722 million, are pledged as collateral to Alliance Pipeline US's lenders and to the lenders to Alliance Pipeline Canada.

## 18. OTHER LONG-TERM LIABILITIES

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Future removal and site restoration reserves *(Note 5)* | **773** | 710 |
| Regulatory liabilities | **198** | 138 |
| Derivative liabilities *(Note 23)* | **133** | 42 |
| Other post-employment benefit liabilities *(Note 27)* | **118** | 110 |
| Other | **251** | 207 |
| | **1,473** | 1,207 |

## 19. NON-CONTROLLING INTERESTS

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| EEM | **394** | 424 |
| EIF | **109** | 134 |
| EGD Preferred Shares | **100** | 100 |
| EGNB | **-** | 54 |
| Talbot Windfarm, LP (Talbot) | **26** | 9 |
| Greenwich Windfarm, LP (Greenwich) | **12** | - |
| Other | **17** | 6 |
| | **658** | 727 |

Non-controlling interests in EEM represents the 82.8% of the listed shares of EEM not held by the Company. Non-controlling interests in EIF represents 58.1% of interests that are held by third parties.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2010, no preferred shares have been redeemed.

During the year ended December 31, 2010, the Company acquired the remaining 27.5% of EGNB limited partnership units held by third parties for $52 million, increasing its partnership interest to 100%.

Non-controlling interests in both Talbot and Greenwich represent 10.0% of partnership units held by a third party.

## 20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares.

### COMMON SHARES

| | **2010** | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| December 31 | Number of Shares | Amount | Number of Shares | Amount | Number of Shares | Amount |
| *(millions of Canadian dollars, number of common shares in millions)* | | | | | | |
| Balance at beginning of year | **378** | **3,379** | 373 | 3,194 | 369 | 3,027 |
| Common shares issued | **-** | **-** | - | 4 | - | - |
| Shares issued on exercise of stock options | **3** | **80** | 1 | 38 | 1 | 36 |
| Dividend Reinvestment and Share Purchase Plan | **4** | **224** | 4 | 143 | 3 | 131 |
| Balance at end of year | **385** | **3,683** | 378 | 3,379 | 373 | 3,194 |

### PREFERRED SHARES

The five million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its

option, redeem all or a portion of the outstanding preferred shares for $25 per share plus all accrued and unpaid dividends.

**EARNINGS PER COMMON SHARE**

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 11 million (2009 - 11 million; 2008 - 11 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

| December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(number of common shares in millions)* | | | |
| Weighted average shares outstanding | **370** | 364 | 360 |
| Effect of dilutive options | **4** | 2 | 3 |
| Diluted weighted average shares outstanding | **374** | 366 | 363 |

For the year ended December 31, 2010, 46,000 anti-dilutive stock options (2009 - 556,500; 2008 - 2,879,800) with a weighted average exercise price of $55.68 (2009 - $40.98; 2008 - $40.53) were excluded from the diluted earnings per share calculation.

**DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN**

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends.

**SHAREHOLDER RIGHTS PLAN**

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

## 21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Based Stock Option (PBSO) Plan, the PSU Plan and the RSU Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 20 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans, of which 0.3 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

**INCENTIVE STOCK OPTIONS**

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2010 for ISOs is $11 million (2009 - $17 million; 2008 - $13 million).

**Outstanding Incentive Stock Options**

| December 31, | **2010** Number | **2010** Weighted Average Exercise Price | 2009 Number | 2009 Weighted Average Exercise Price | 2008 Number | 2008 Weighted Average Exercise Price |
|---|---|---|---|---|---|---|
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| Options at beginning of year | **12,466** | **34.01** | 10,650 | 31.05 | 9,237 | 27.24 |
| Options granted | **2,000** | **45.40** | 3,028 | 39.62 | 2,642 | 40.54 |
| Options exercised | **(1,718)** | **29.04** | (1,187) | 22.01 | (1,178) | 21.85 |
| Options cancelled or expired | **(18)** | **24.89** | (25) | 40.65 | (51) | 36.83 |
| Options at end of year | **12,730** | **36.48** | 12,466 | 34.01 | 10,650 | 31.05 |
| Options vested | **6,882** | **32.01** | 6,550 | 28.96 | 6,087 | 25.32 |

The total intrinsic value of ISOs exercised during the year ended December 31, 2010 was $38 million (2009 - $22 million; 2008 - $23 million) and cash received on exercise was $50 million (2009 - $26 million; 2008 - $26 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2010 was $182 million (2009 - $81 million) and $131 million (2009 - $76 million), respectively.

**Incentive Stock Option Characteristics**

| **December 31, 2010** | Options Outstanding | | | Options Vested | | |
|---|---|---|---|---|---|---|
| Exercise Price Range | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| 15.00-19.99 | **222** | **0.1** | **19.10** | **222** | **0.1** | **19.10** |
| 20.00-24.99 | **1,399** | **1.7** | **21.27** | **1,399** | **1.7** | **21.27** |
| 25.00-29.99 | **851** | **3.1** | **25.72** | **851** | **3.1** | **25.72** |
| 30.00-34.99 | **1,487** | **5.7** | **31.68** | **1,017** | **4.6** | **31.74** |
| 35.00-39.99 | **4,336** | **7.0** | **38.55** | **2,262** | **6.1** | **37.75** |
| 40.00-44.99 | **2,783** | **7.4** | **40.82** | **1,131** | **7.1** | **40.39** |
| 45.00-49.99 | **1,606** | **9.1** | **46.59** | **-** | **-** | **-** |
| 55.00-59.99 | **46** | **9.9** | **55.68** | **-** | **-** | **-** |
| | **12,730** | **6.2** | **36.48** | **6,882** | **4.6** | **32.01** |

The total fair value of options vested under the ISO Plan during the year ended December 31, 2010 was $14 million (2009 - $13 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| Fair value per option *(Canadian dollars)*[1] | **6.88** | 7.12 | 6.14 |
| Valuation assumptions | | | |
| Expected option term *(years)*[2] | **6** | 6 | 6 |
| Expected volatility[3] | **19.72%** | 28.08% | 18.48% |
| Expected dividend yield[4] | **3.64%** | 3.87% | 3.34% |
| Risk-free interest rate[5] | **2.70%** | 2.24% | 3.50% |

*1 Options granted to United States employees are based on New York Stock Exchange (NYSE) prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair values per option were $6.56 (2009 - $6.73; 2008 - $6.20) for Canadian employees and US$8.00 (2009 - US$6.86; 2008 - US$5.82) for United States employees.*

*2 The expected option term is based on historical exercise practice.*

*3 Expected volatility is determined with reference to historic daily share price volatility and beginning in 2010, implied volatility observable in call option values near the grant date.*

*4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

*5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and U.S. Treasury Bond Yields.*

As of December 31, 2010, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $16 million. The cost is expected to be fully recognized by December 31, 2013.

**PERFORMANCE BASED STOCK OPTIONS**

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2010 for PBSOs was $2 million (2009 - $2 million; 2008 - $2 million).

**Outstanding Performance Based Stock Options**

| December 31, | **2010** | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| Options at beginning of year | **3,395** | **33.69** | 3,738 | 32.72 | 3,588 | 31.92 |
| Options granted | - | - | - | - | 250 | 40.42 |
| Options exercised | **(1,039)** | **26.24** | (343) | 23.15 | (100) | 23.15 |
| Options cancelled | **(209)** | **36.57** | - | - | - | - |
| Options at end of year | **2,147** | **37.02** | 3,395 | 33.69 | 3,738 | 32.72 |
| Options vested | **1,262** | **36.88** | 800 | 23.15 | 1,143 | 23.15 |

The total intrinsic value of PBSOs exercised during the year ended December 31, 2010 was $26 million (2009 - $6 million; 2008 - $2 million) and cash received on exercise was $27 million (2009 - $8 million; 2008 - $2 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2010 is $30 million (2009 - $23 million) and $18 million (2009 - $14 million), respectively.

**Performance Based Stock Option Characteristics**

| **December 31, 2010** | Options Outstanding | | | Options Vested | | |
|---|---|---|---|---|---|---|
| Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| 36.57 | **1,897** | **4.6** | **36.57** | **1,162** | **4.6** | **36.57** |
| 40.42 | **250** | **4.6** | **40.42** | **100** | **4.6** | **40.42** |
| | **2,147** | **4.6** | **37.02** | **1,262** | **4.6** | **36.88** |

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2010 was $2 million (2009 - $2 million; 2008 - $2 million).

Assumptions used to determine the fair value of the PBSOs at the date of grant using the Bloomberg barrier option valuation model are as follows:

| Year ended December 31, | 2008 |
|---|---|
| Fair value per option *(Canadian dollars)* | 4.82 |
| Valuation assumptions | |
| Expected option term *(years)*[1] | 8 |
| Expected volatility[2] | 13.60% |
| Expected dividend yield[3] | 3.32% |
| Risk-free interest rate[4] | 3.75% |

*1 Expected option term is based on historical information.*

*2 Expected volatility is determined with reference to 20-day rolling period historic share price information.*

*3 The expected dividend yield is the current annual dividend divided by the current stock price.*

*4 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

As of December 31, 2010, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $3 million. The cost is expected to be fully recognized by December 31, 2012.

**PERFORMANCE STOCK UNITS**

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2008, 2009 and 2010 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2010 for PSUs was $27 million (2009 - $20 million; 2008 - $13 million). To calculate the 2010 expense, multipliers of two, based upon multiplier estimates at December 31, 2010, were used for each of the 2008, 2009 and 2010 PSU grants.

**Outstanding Performance Stock Units**

| December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| Units at beginning of year | **330,416** | 295,428 | 267,616 |
| Units granted | **286,200** | 169,600 | 144,300 |
| Units cancelled | **-** | - | - |
| Units matured | **(159,817)** | (151,882) | (129,852) |
| Dividend reinvestment | **21,148** | 17,270 | 13,364 |
| Units at end of year | **477,947** | 330,416 | 295,428 |

Of the PSUs outstanding at December 31, 2010, 181,932 units have a performance period ending December 31, 2011 and 296,015 have a performance period ending December 31, 2012. The total intrinsic value of PSUs outstanding at December 31, 2010 is $56 million (2009 - $47 million; 2008 - $21 million).

**RESTRICTED STOCK UNITS**

Enbridge has a RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2010 for RSUs was $29 million (2009 - $23 million; 2008 - $15 million).

**Outstanding Restricted Stock Units**

| December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| Units at beginning of year | **987,877** | 700,034 | 456,621 |
| Units granted | **468,600** | 543,500 | 418,700 |
| Units cancelled | **(30,454)** | (18,429) | (23,352) |
| Units matured | **(427,752)** | (282,656) | (179,940) |
| Dividend reinvestment | **49,714** | 45,428 | 28,005 |
| Units at end of year | **1,047,985** | 987,877 | 700,034 |

The total intrinsic value of RSUs outstanding at December 31, 2010 is $63 million (2009 - $50 million; 2008 - $29 million).

As of December 31, 2010, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $62 million and is expected to be fully recognized by December 31, 2012.

# 22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

| | Net Investment Hedges | Cumulative Translation Adjustment | Equity Investees | Non-Controlling Interests | Cash Flow Hedges | Total |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at January 1, 2008 | 438 | (933) | (57) | 118 | 149 | (285) |
| Changes during the year | (180) | 658 | 78 | (101) | (175) | 280 |
| Tax impact | 20 | - | (29) | - | 47 | 38 |
| | (160) | 658 | 49 | (101) | (128) | 318 |
| Balance at December 31, 2008 | 278 | (275) | (8) | 17 | 21 | 33 |
| Changes during the year | 181 | (815) | (38) | 72 | 71 | (529) |
| Tax impact | (30) | - | 14 | - | (31) | (47) |
| | 151 | (815) | (24) | 72 | 40 | (576) |
| Balance at December 31, 2009 | 429 | (1,090) | (32) | 89 | 61 | (543) |
| Changes during the year | **61** | **(274)** | **(18)** | **33** | **(133)** | **(331)** |
| Tax impact | **(10)** | - | **7** | - | **(5)** | **(8)** |
| | **51** | **(274)** | **(11)** | **33** | **(138)** | **(339)** |
| Balance at December 31, 2010 | **480** | **(1,364)** | **(43)** | **122** | **(77)** | **(882)** |

# 23. RISK MANAGEMENT

**MARKET PRICE RISK**

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

**Foreign Exchange Risk**
The Company's earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2010, would have resulted in a $81 million increase (2009 - $92 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI, therefore a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

**Interest Rate Risk**
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2014 at an average rate of 2.1%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2014. A total of $2,000 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.4%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

At December 31, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would not have had an impact (2009 - $2 million increase) in earnings and would have caused a $178 million increase (2009 - $197 million increase) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2010, and a $22 million decrease (2009 - $26 million decrease) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

**Commodity Price Risk**
The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership in the Aux Sable natural gas processing plant through 2011.

The Company has defined EaR limits for different components of businesses exposed to commodity price risk. The calculation of these limits reflect physical and financial derivatives as well as physical transportation and storage capacity contracts accounted for as executory contracts in the consolidated financial statements. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from commodity price risk over a one month period:

| | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Average EaR during the year | **22** | 22 |
| High EaR during the year | **29** | 32 |
| Low EaR during the year | **16** | 16 |
| Closing EaR at year end | **25** | 19 |

**TOTAL DERIVATIVE INSTRUMENTS**

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges as at December 31, 2010 or December 31, 2009.

| **December 31, 2010** | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment Hedges | Non-Qualifying Derivative Instruments | Total Derivative Instruments |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Accounts receivable and other *(Note 7)* | | | | |
| Foreign exchange contracts | **4** | **15** | **111** | **130** |
| Interest rate contracts | **6** | **-** | **-** | **6** |
| Commodity contracts | **-** | **-** | **33** | **33** |
| Other contracts | **-** | **-** | **1** | **1** |
| | **10** | **15** | **145** | **170** |
| Deferred amounts and other *(Note 12)* | | | | |
| Foreign exchange contracts | **18** | **100** | **275** | **393** |
| Interest rate contracts | **67** | **-** | **-** | **67** |
| Commodity contracts | **-** | **-** | **2** | **2** |
| | **85** | **100** | **277** | **462** |
| Accounts payable and other *(Note 15)* | | | | |
| Foreign exchange contracts | **(4)** | **-** | **(11)** | **(15)** |
| Interest rate contracts | **(72)** | **-** | **-** | **(72)** |
| Commodity contracts | **-** | **-** | **(51)** | **(51)** |
| | **(76)** | **-** | **(62)** | **(138)** |
| Other long-term liabilities *(Note 18)* | | | | |
| Foreign exchange contracts | **(47)** | **-** | **(3)** | **(50)** |
| Interest rate contracts | **(80)** | **-** | **-** | **(80)** |
| Commodity contracts | **-** | **-** | **(3)** | **(3)** |
| | **(127)** | **-** | **(6)** | **(133)** |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | **(29)** | **115** | **372** | **458** |
| Interest rate contracts | **(79)** | **-** | **-** | **(79)** |
| Commodity contracts | **-** | **-** | **(19)** | **(19)** |
| Other contracts | **-** | **-** | **1** | **1** |
| | **(108)** | **115** | **354** | **361** |

| December 31, 2009 | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment Hedges | Non-Qualifying Derivative Instruments | Total Derivative Instruments |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Accounts receivable and other *(Note 7)* | | | | |
| Foreign exchange contracts | 4 | 14 | 52 | 70 |
| Interest rate contracts | 34 | - | 2 | 36 |
| Commodity contracts | - | - | 22 | 22 |
| | 38 | 14 | 76 | 128 |
| Deferred amounts and other *(Note 12)* | | | | |
| Foreign exchange contracts | 25 | 80 | 285 | 390 |
| Interest rate contracts | 90 | - | - | 90 |
| Commodity contracts | 1 | - | 2 | 3 |
| Other contracts | 1 | - | 1 | 2 |
| | 117 | 80 | 288 | 485 |
| Accounts payable and other *(Note 15)* | | | | |
| Foreign exchange contracts | (2) | - | (3) | (5) |
| Interest rate contracts | (68) | - | - | (68) |
| Commodity contracts | (17) | - | (33) | (50) |
| | (87) | - | (36) | (123) |
| Other long-term liabilities *(Note 18)* | | | | |
| Foreign exchange contracts | (21) | - | - | (21) |
| Interest rate contracts | (15) | - | - | (15) |
| Commodity contracts | (4) | - | (2) | (6) |
| | (40) | - | (2) | (42) |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | 6 | 94 | 334 | 434 |
| Interest rate contracts | 41 | - | 2 | 43 |
| Commodity contracts | (20) | - | (11) | (31) |
| Other contracts | 1 | - | 1 | 2 |
| | 28 | 94 | 326 | 448 |

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

| | **December 31, 2010** | | December 31, 2009 | |
|---|---|---|---|---|
| | Maturity | Notional Principal or Quantity Outstanding | Maturity | Notional Principal or Quantity Outstanding |
| U.S. dollar forwards - purchase *(millions of United States dollars)* | **2011-2020** | **1,185** | 2010-2019 | 1,078 |
| U.S. dollar forwards - sell *(millions of United States dollars)* | **2011-2020** | **3,516** | 2010-2020 | 3,102 |
| Interest rate contracts *(millions of Canadian dollars)* | **2011-2029** | **10,772** | 2010-2029 | 6,022 |
| Commodity contracts - Energy *(bcfe)* | **2011-2013** | **41** | 2010-2011 | 464 |
| Commodity contracts - Power *(MW/H)* | **2011-2024** | **2** | 2010-2024 | 38 |

**The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income**
The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

| Year ended December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Amount of Unrealized Gain/(Loss) Recognized in OCI | | |
| Cash Flow Hedges | | |
| Foreign exchange contracts | **(25)** | (116) |
| Interest rate contracts | **(172)** | 73 |
| Commodity contracts | **97** | (37) |
| Other contracts | **(1)** | 3 |
| Net Investment Hedges | | |
| Foreign exchange contracts | **19** | 24 |
| Total unrealized loss recognized in OCI | **(82)** | (53) |
| Amount of Gain/(Loss) Reclassified from AOCI to Earnings | | |
| Foreign exchange contracts[1] | **(7)** | (4) |
| Interest rate contracts[2] | **68** | (31) |
| Commodity contracts[3] | **(95)** | (79) |
| Other contracts | **1** | 3 |
| Total loss reclassified from AOCI to earnings | **(33)** | (111) |

*1 Loss reported within Other Income in the Consolidated Statement of Earnings.*

*2 Gain/(loss) reported within Interest Expense in the Consolidated Statement of Earnings.*

*3 Loss reported within Commodity costs in the Consolidated Statement of Earnings.*

The Company estimates that $71 million of accumulated other comprehensive loss related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2010.

**Non-Qualifying Derivatives**
The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Foreign exchange contracts[1] | **33** | 232 | 35 |
| Interest rate contracts[2] | **(2)** | 2 | - |
| Commodity contracts[3] | **(5)** | (88) | 122 |
| Total unrealized derivative fair value gain | **26** | 146 | 157 |

*1 Gain reported within Other Income in the Consolidated Statement of Earnings.*

*2 Gain/(loss) reported within Interest Expense in the Consolidated Statement of Earnings.*

*3 Gain/(loss) reported within Commodity costs in the Consolidated Statement of Earnings.*

Additional information regarding the Company's derivative instruments is included in Note 24, Fair Value of Financial Instruments.

**LIQUIDITY RISK**
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the

Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

**Maturities of Financial Instruments**
The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17).*

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Cash inflows | 256 | 136 | 151 | 152 | 59 | 43 |
| Cash outflows | (224) | (50) | (45) | (25) | (4) | (52) |
| Net cash flows | 32 | 86 | 106 | 127 | 55 | (9) |

**CREDIT RISK**
Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

At December 31, 2010 and 2009, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following geographic regions:

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canadian financial institutions | **373** | 474 |
| Non-Canadian financial institutions | **(12)** | (26) |
| | **361** | 448 |

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, Fair Value of Financial Instruments.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

| Year ended December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Balance at beginning of year | **(74)** | (69) |
| Additional allowance | **(23)** | (29) |
| Amounts used | **35** | 24 |
| Balance at end of year | **(62)** | (74) |

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

## 24. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

| **December 31, 2010** | Held for Trading | Available for Sale[1] | Loans and Receivables | Held to Maturity | Other Financial Liabilities | Qualifying Derivatives | Non-Financial Instruments | Total | Fair Value[2] |
|---|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | | |
| **Assets** | | | | | | | | | |
| Cash and cash equivalents | **242** | **-** | **-** | **-** | **-** | **-** | **-** | **242** | **242** |
| Accounts receivable and other | **145** | **-** | **2,113** | **-** | **-** | **25** | **423** | **2,706** | **2,283** |
| Long-term investments | **-** | **54** | **339** | **181** | **-** | **-** | **1,624** | **2,198** | **520** |
| Deferred amounts and other assets | **277** | **-** | **334** | **-** | **-** | **185** | **2,090** | **2,886** | **462** |
| **Liabilities** | | | | | | | | | |
| Short-term borrowings | **-** | **-** | **-** | **-** | **326** | **-** | **-** | **326** | **326** |
| Accounts payable and other | **62** | **-** | **-** | **-** | **2,393** | **76** | **157** | **2,688** | **2,531** |
| Interest payable | **-** | **-** | **-** | **-** | **117** | **-** | **-** | **117** | **117** |
| Long-term debt | **-** | **-** | **-** | **-** | **13,715** | **-** | **-** | **13,715** | **14,770** |
| Non-recourse long-term debt | **-** | **-** | **-** | **-** | **1,131** | **-** | **-** | **1,131** | **1,298** |
| Other long-term liabilities | **6** | **-** | **-** | **-** | **-** | **127** | **1,340** | **1,473** | **133** |

| December 31, 2009 | Held for Trading | Available for Sale[1] | Loans and Receivables | Held to Maturity | Other Financial Liabilities | Qualifying Derivatives | Non-Financial Instruments | Total | Fair Value[2] |
|---|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | | |
| **Assets** | | | | | | | | | |
| Cash and cash equivalents | 327 | - | - | - | - | - | - | 327 | 327 |
| Accounts receivable and other | 76 | - | 2,054 | - | - | 52 | 302 | 2,484 | 2,182 |
| Long-term investments | - | 54 | 6 | 181 | - | - | 2,071 | 2,312 | 187 |
| Deferred amounts and other assets | 288 | - | - | - | - | 197 | 1,940 | 2,425 | 485 |
| **Liabilities** | | | | | | | | | |
| Short-term borrowings | - | - | - | - | 508 | - | - | 508 | 508 |
| Accounts payable and other | 36 | - | - | - | 2,237 | 87 | 103 | 2,463 | 2,360 |
| Interest payable | - | - | - | - | 104 | - | - | 104 | 104 |
| Long-term debt | - | - | - | - | 12,467 | - | - | 12,467 | 13,773 |
| Non-recourse long-term debt | - | - | - | - | 1,221 | - | - | 1,221 | 1,250 |
| Other long-term liabilities | 2 | - | - | - | - | 40 | 1,165 | 1,207 | 42 |

*1 Classified as Other Investments carried at Cost under U.S. GAAP.*

*2 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

**FAIR VALUE OF DERIVATIVES**

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

**Level 1**

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment.

**Level 2**

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services and Corporate segments.

**Level 3**

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread

as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

| **December 31, 2010** | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets: | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | **-** | **130** | **-** | **130** |
| Interest rate contracts | **-** | **6** | **-** | **6** |
| Commodity contracts | **-** | **5** | **28** | **33** |
| Other contracts | **-** | **-** | **1** | **1** |
| | **-** | **141** | **29** | **170** |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | **-** | **393** | **-** | **393** |
| Interest rate contracts | **-** | **67** | **-** | **67** |
| Commodity contracts | **-** | **-** | **2** | **2** |
| | **-** | **460** | **2** | **462** |
| Financial liabilities: | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | **-** | **(15)** | **-** | **(15)** |
| Interest rate contracts | **-** | **(72)** | **-** | **(72)** |
| Commodity contracts | **(9)** | **(2)** | **(40)** | **(51)** |
| | **(9)** | **(89)** | **(40)** | **(138)** |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | **-** | **(50)** | **-** | **(50)** |
| Interest rate contracts | **-** | **(80)** | **-** | **(80)** |
| Commodity contracts | **-** | **(1)** | **(2)** | **(3)** |
| | **-** | **(131)** | **(2)** | **(133)** |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | **-** | **458** | **-** | **458** |
| Interest rate contracts | **-** | **(79)** | **-** | **(79)** |
| Commodity contracts | **(9)** | **2** | **(12)** | **(19)** |
| Other contracts | **-** | **-** | **1** | **1** |
| | **(9)** | **381** | **(11)** | **361** |

| December 31, 2009 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets: | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | - | 70 | - | 70 |
| Interest rate contracts | - | 36 | - | 36 |
| Commodity contracts | 2 | - | 20 | 22 |
| | 2 | 106 | 20 | 128 |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | - | 390 | - | 390 |
| Interest rate contracts | - | 90 | - | 90 |
| Commodity contracts | - | - | 3 | 3 |
| Other contracts | - | 2 | - | 2 |
| | - | 482 | 3 | 485 |
| Financial liabilities: | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | - | (5) | - | (5) |
| Interest rate contracts | - | (68) | - | (68) |
| Commodity contracts | (2) | - | (48) | (50) |
| | (2) | (73) | (48) | (123) |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | - | (21) | - | (21) |
| Interest rate contracts | - | (15) | - | (15) |
| Commodity contracts | - | (3) | (3) | (6) |
| | - | (39) | (3) | (42) |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | - | 434 | - | 434 |
| Interest rate contracts | - | 43 | - | 43 |
| Commodity contracts | - | (3) | (28) | (31) |
| Other contracts | - | 2 | - | 2 |
| | - | 476 | (28) | 448 |

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

| Year ended December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Level 3 net derivative asset/(liability) at beginning of year | **(28)** | 53 |
| Total gains/(losses), unrealized | | |
| Included in earnings[1] | **19** | (27) |
| Included in OCI | **3** | 7 |
| Settlements | **(5)** | (61) |
| Level 3 net derivative liability at end of year | **(11)** | (28) |

*1 Gain/(loss) reported within Commodity Costs in the Consolidated Statement of Earnings.*

*2 The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2010 or 2009.*

# 25. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and non-controlling interests less cash and cash equivalents (excluding cash and cash equivalents from joint ventures and other interests not exclusively controlled by the Company). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows:

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Short-term borrowings | **326** | 508 |
| Long-term debt (includes current portion) | **13,810** | 12,570 |
| Non-controlling interests | **658** | 727 |
| Shareholders' equity[1] | **8,601** | 7,958 |
| Cash and cash equivalents | **(172)** | (258) |
| | **23,223** | 21,505 |

*1 Excludes AOCI and reciprocal shareholdings.*

The Company's objectives when managing capital are to maintain flexibility among: enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; and, providing acceptable returns to shareholders. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2010, including short-term borrowings but excluding non-recourse short and long-term debt, was 65.0% compared with 64.1% at the end of 2009.

The Company must adhere to covenants in its credit facilities that are used to backstop its commercial paper program. These covenants include maintaining a minimum consolidated shareholders' equity balance of $1,000 million and an unconsolidated debt to unconsolidated shareholders' equity ratio of less than 1.5. As at December 31, 2010, the Company was in compliance with these covenants.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. Total consolidated capitalization consists of shareholders' equity, long-term debt, non-controlling interests and future income tax. As at December 31, 2010, the Company was in compliance with this covenant.

# 26. INCOME TAXES

**INCOME TAX RATE RECONCILIATION**

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | **1,221** | 1,868 | 1,837 |
| Combined statutory income tax rate | **28.9%** | 30.5% | 31.3% |
| Income taxes at statutory rate | **353** | 570 | 575 |
| Increase/(decrease) resulting from: | | | |
| Future income taxes related to regulated operations | **(62)** | (68) | (15) |
| Higher/(lower) foreign tax rates | **(22)** | (61) | 3 |
| Tax rates and legislated tax changes | **(23)** | (58) | (11) |
| Non-taxable items, net | **(2)** | 11 | 2 |
| Sale of investments | **-** | (99) | (82) |
| Other | **7** | 11 | 37 |
| Income taxes | **251** | 306 | 509 |
| Effective income tax rate | **20.6%** | 16.4% | 27.7% |

**COMPONENTS OF FUTURE INCOME TAXES**

| December 31, | **2010** | 2009 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Net Future Income Tax Liabilities/(Assets) | | |
| Differences in accounting and tax bases of property, plant and equipment | **1,468** | 1,346 |
| Differences in accounting and tax bases of investments | **479** | 407 |
| Regulatory assets/(liabilities) | **340** | 319 |
| Financial instruments | **105** | 121 |
| Loss carryforwards | **(81)** | (138) |
| Other | **56** | 29 |
| Net Future Income Tax Liability | **2,367** | 2,084 |

Net future income tax liability of $2,367 million (2009 - $2,084 million) is comprised of future income tax liabilities of $2,447 million (2009 - $2,211 million) net of future income tax assets of $80 million (2009 - $127 million).

At December 31, 2010, the Company has recognized the benefit of unused tax loss carryforwards of $248 million (2009 - $425 million) of which $246 million start to expire in 2019 and beyond.

**GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES**

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | | | |
| Canada | **711** | 954 | 624 |
| United States | **379** | 334 | 419 |
| Other | **131** | 580 | 794 |
| | **1,221** | 1,868 | 1,837 |
| Current income taxes | | | |
| Canada | **(29)** | 49 | 141 |
| United States | **37** | 35 | 43 |
| Other | **5** | 4 | 67 |
| | **13** | 88 | 251 |
| Future income taxes | | | |
| Canada | **134** | 117 | 92 |
| United States | **104** | 101 | 166 |
| | **238** | 218 | 258 |
| Current and future income taxes | **251** | 306 | 509 |

## 27. POST EMPLOYMENT BENEFITS

**PENSION PLANS**

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2010 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

**Defined Benefit Plans**

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

| | Effective Date of Most Recently Filed Actuarial Valuation | Effective Date of Next Required Actuarial Valuation |
|---|---|---|
| Canadian Plans | | |
| Liquids Pipelines | December 31, 2009 | December 31, 2010 |
| Gas Distribution | December 31, 2009 | December 31, 2012 |
| United States Plan | December 31, 2009 | December 31, 2010 |

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

**Defined Contribution Plans**
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

**Post-employment Benefits Other than Pensions**
OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

**DEFINED BENEFIT PLANS**
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| December 31, | **2010** | 2009 | **2010** | 2009 |
| *(millions of Canadian dollars)* | | | | |
| **Change in Accrued Benefit Obligation** | | | | |
| Benefit obligation at beginning of year | **1,119** | 1,075 | **170** | 179 |
| Service cost | **48** | 53 | **5** | 4 |
| Interest cost | **72** | 71 | **11** | 11 |
| Amendments | **-** | - | **6** | - |
| Employees' contributions | **-** | - | **1** | 1 |
| Actuarial loss/(gain) [1] | **145** | (13) | **12** | (1) |
| Benefits paid | **(52)** | (51) | **(7)** | (8) |
| Effect of foreign exchange rate changes | **(9)** | (16) | **(3)** | (16) |
| Benefit obligation at end of year | **1,323** | 1,119 | **195** | 170 |
| **Change in Plan Assets** | | | | |
| Fair value of plan assets at beginning of year | **1,167** | 1,141 | **38** | 46 |
| Actual return on plan assets[1] | **127** | 51 | **2** | 6 |
| Employer's contributions | **89** | 44 | **9** | 9 |
| Employees' contributions | **-** | - | **1** | 1 |
| Benefits paid | **(52)** | (51) | **(7)** | (8) |
| Other | **(1)** | (1) | **-** | (8) |
| Effect of foreign exchange rate changes | **(6)** | (17) | **(2)** | (8) |
| Fair value of plan assets at end of year | **1,324** | 1,167 | **41** | 38 |
| **Funded Status** | | | | |
| Benefit obligation | **(1,323)** | (1,119) | **(195)** | (170) |
| Fair value of plan assets | **1,324** | 1,167 | **41** | 38 |
| Overfunded/(Underfunded) status at end of year | **1** | 48 | **(154)** | (132) |
| Contribution after measurement date | **-** | 14 | **-** | 1 |
| Unamortized prior service cost | **4** | 6 | **6** | - |
| Unamortized transitional obligation/(asset) | **(11)** | (13) | **8** | 9 |
| Unamortized net loss | **307** | 161 | **22** | 12 |
| Net amount recognized in the Consolidated Statement of Financial Position at end of year | **301** | 216 | **(118)** | (110) |
| Presented as follows: | | | | |
| Deferred Amounts and Other Assets *(Note 12)* | **301** | 216 | **-** | - |
| Other Long-Term Liabilities *(Note 18)* | **-** | - | **(118)** | (110) |

*1 Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 |
| Discount rate | **5.64%** | 6.46% | 6.59% | **5.55%** | 6.28% | 6.42% |
| Average rate of salary increases | **3.50%** | 3.73% | 5.00% | | | |

**Net Benefit Costs Recognized**

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 |
| *(millions of Canadian dollars)* | | | | | | |
| Benefits earned during the year | **48** | 53 | 53 | **5** | 4 | 5 |
| Interest cost on projected benefit obligations | **72** | 71 | 65 | **11** | 11 | 11 |
| Actual return on plan assets | **(127)** | (51) | 180 | **(2)** | (6) | 12 |
| Difference between actual and expected return on plan assets | **47** | (27) | (273) | **-** | 3 | (15) |
| Amortization of prior service costs | **2** | 2 | 2 | **-** | - | - |
| Amortization of transitional obligation | **(2)** | (2) | (2) | **1** | 1 | 1 |
| Amortization of actuarial loss | **19** | 21 | 4 | **1** | 1 | 1 |
| Amount charged to EEP[1] | **(15)** | (20) | (8) | **(5)** | (5) | (3) |
| Net defined benefit costs on an accrual basis | **44** | 47 | 21 | **11** | 9 | 12 |
| Adjustment to cash basis for amounts in EGD[2] | **-** | - | (3) | **-** | - | 6 |
| Defined contribution benefit costs | **5** | 4 | 4 | **-** | - | - |
| Net benefit cost recognized in the Consolidated Statements of Earnings | **49** | 51 | 22 | **11** | 9 | 18 |

1 *EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.*

2 *Prior to January 1, 2009, the Company recognized pension benefit costs related to its regulated EGD pension plan on the cash basis.*

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2010** | 2009 | 2008 | **2010** | 2009 | 2008 |
| Discount rate | **6.47%** | 6.59% | 5.65% | **6.31%** | 6.42% | 5.71% |
| Average rate of return on pension plan assets | **7.30%** | 7.30% | 7.30% | **6.00%** | 6.09% | 6.00% |
| Average rate of salary increases | **3.73%** | 5.00% | 5.00% | | | |

**MEDICAL COST TRENDS**

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

| | Medical Cost Trend Rate Assumption for Next Fiscal Year | Ultimate Medical Cost Trend Rate Assumption | Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved |
|---|---|---|---|
| Canadian Plans | | | |
| Drugs | 9.4% | 4.5% | 2029 |
| Other Medical and Dental | 4.5% | 4.5% | 2010 |
| United States Plan | 8.0% | 4.5% | 2030 |

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $29 million in the accumulated post-employment benefit obligations and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $23 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

**PLAN ASSETS**

The Company manages the investment risk of its defined benefit pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

**Target Mix for Plan Assets**

| | Liquids Pipelines Pension Plan | Gas Distribution Pension Plan | Enbridge United States Pension Plan |
|---|---|---|---|
| Equity securities | 62.5% | 52.5% | 57.5% |
| Fixed income securities | 32.5% | 42.5% | 37.5% |
| Other | 5.0% | 5.0% | 5.0% |

**Expected Rate of Return on Plan Assets**

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | **2010** | 2009 | **2010** | 2009 |
| Canadian Plans | **7.25%** | 7.25% | **6.00%** | 6.00% |
| United States Plan | **7.75%** | 7.75% | **6.00%** | 6.00% |

**Major Categories of Plan Assets**

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2010, assets securing pension benefits were invested 60.2% (2009 - 54.7%) in equity securities, 33.8% (2009 - 34.0%) in fixed income securities and 6.0% (2009 - 11.3%) in other. OPEB assets securing OPEB benefits were invested 51.2% (2009 - 60.5%) in equity securities and 48.8% (2009 - 39.5%) in fixed income securities.

| | December 31, 2010 | | | | December 31, 2009 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1[1] | Level 2[2] | Level 3[3] | Total | Level 1[1] | Level 2[2] | Level 3[3] | Total |
| *(millions of Canadian dollars)* | | | | | | | | |
| **Pension Benefits:** | | | | | | | | |
| Cash and cash equivalents | **10** | **-** | **-** | **10** | 65 | - | - | 65 |
| Fixed income securities: | | | | | | | | |
| Canadian government bonds | **-** | **97** | **-** | **97** | - | 82 | - | 82 |
| Corporate bonds and debentures | **4** | **-** | **-** | **4** | 4 | - | - | 4 |
| Canadian corporate bond index fund | **151** | **-** | **-** | **151** | 131 | - | - | 131 |
| Canadian government bond index fund | **149** | **-** | **-** | **149** | 137 | - | - | 137 |
| United States debt index fund | **47** | **-** | **-** | **47** | 43 | - | - | 43 |
| Equity: | | | | | | | | |
| Canadian equity securities | **163** | **-** | **-** | **163** | 150 | - | - | 150 |
| Canadian equity funds | **26** | **80** | **-** | **106** | 89 | - | - | 89 |
| United States equity funds | **147** | **76** | **-** | **223** | 117 | - | - | 117 |
| Global equity funds | **221** | **19** | **-** | **240** | 127 | 117 | - | 244 |
| Private equity investment[4] | **-** | **-** | **65** | **65** | - | - | 37 | 37 |
| Exchange-traded foreign currency derivatives | **-** | **-** | **-** | **-** | 1 | - | - | 1 |
| Other: | | | | | | | | |
| Refundable taxes receivable[5] | **-** | **-** | **68** | **68** | - | - | 62 | 62 |
| Other net receivables/(payables) | **-** | **-** | **-** | **1** | - | - | - | 5 |
| | **918** | **272** | **133** | **1,324** | 864 | 199 | 99 | 1,167 |
| **OPEB:** | | | | | | | | |
| Fixed income securities: | | | | | | | | |
| United States government and government agency bonds | **20** | **-** | **-** | **20** | - | 15 | - | 15 |
| Equity: | | | | | | | | |
| United States equity funds | **9** | **-** | **-** | **9** | - | - | - | - |
| Global equity funds | **-** | **12** | **-** | **12** | 23 | - | - | 23 |
| | **29** | **12** | **-** | **41** | 23 | 15 | - | 38 |

*1 Level 1 assets include assets with quoted prices in active markets for identical assets.*

*2 Level 2 assets include assets with significant observable inputs.*

*3 Level 3 assets include assets with significant unobservable inputs.*

*4 The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.*

*5 The fair value of refundable taxes receivable approximates carrying value due to the nature of the receivable and the short period to maturity.*

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

| | Private Equity Investment | Refundable Taxes Receivable |
|---|---|---|
| Balance at beginning of year | **37** | **62** |
| Total gains, unrealized | **2** | **-** |
| Purchases, issuances, settlements | **26** | **6** |
| Balance at end of year | **65** | **68** |

**PLAN CONTRIBUTIONS BY THE COMPANY**

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | **2010** | 2009 | **2010** | 2009 |
| *(millions of Canadian dollars)* | | | | |
| Total contributions | **89** | **44** | **9** | **9** |
| Contributions expected to be paid in 2011 | **90** | | **10** | |

**BENEFITS EXPECTED TO BE PAID BY THE COMPANY**

| Year ended December 31, | 2011 | 2012 | 2013 | 2014 | 2015 | 2016-2020 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Expected future benefit payments | 61 | 64 | 67 | 71 | 74 | 437 |

## 28. OTHER INCOME

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Net foreign currency gains | **132** | 444 | 43 |
| Gain on reduction of EEP ownership interest | **81** | - | 13 |
| Allowance for equity funds used during construction (AEDC) | **80** | 135 | 59 |
| Interest income on affiliate loans | **37** | 38 | 34 |
| Noverco preferred dividends income | **15** | 15 | 16 |
| Hurricane insurance recoveries | **5** | 13 | - |
| OCENSA investment income | **-** | 6 | 23 |
| Other | **24** | 27 | 10 |
| | **374** | 678 | 198 |

## 29. CHANGES IN OPERATING ASSETS AND LIABILITIES

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Accounts receivable and other | **(478)** | 76 | 186 |
| Inventory | **(42)** | 99 | (135) |
| Deferred amounts and other assets | **(99)** | (349) | 95 |
| Accounts payable and other | **283** | 134 | (115) |
| Interest payable | **13** | 2 | 9 |
| Other long-term liabilities | **60** | 281 | (66) |
| | **(263)** | 243 | (26) |

## 30. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| EEP | **332** | 342 | 302 |
| Vector Pipeline | **7** | 6 | 6 |
| | **339** | 348 | 308 |

At December 31, 2010, the Company has accounts receivable of $29 million (2009 - $38 million) from EEP and nil (2009 - $1 million) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty. At December 31, 2009, there was no amount outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Alliance Pipeline Canada | **25** | 24 | 24 |
| Alliance Pipeline US | **17** | 18 | 17 |
| Vector Pipeline | **28** | 29 | 27 |
| | **70** | 71 | 68 |

Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Purchases | **2** | 16 | 52 |
| Sales | **-** | (6) | (7) |
| | **2** | 10 | 45 |

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services Inc. and Enbridge Gas Services (US) Inc., respectively, subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Alliance Pipeline Canada | **13** | 9 | 9 |
| Alliance Pipeline US | **9** | 7 | 7 |
| Vector Pipeline | **10** | 16 | 16 |
| | **32** | 32 | 32 |

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Purchases | **151** | 80 | 24 |
| Sales | **(3)** | (7) | (9) |
| | **148** | 73 | 15 |

**ALBERTA CLIPPER PROJECT**
In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2010, the Company had substantially met all funding commitments.

The Company funded 66.7% of the project's equity requirements through EELP, an equity investee. The Company also provided a $346 million (US$347 million) (2009 - $282 million (US$270 million)) loan to EEP for debt financing related to the construction. At December 31, 2010, $334 million is included in Deferred Amounts and Other Assets with the remaining $12 million included in Accounts Receivable and Other (2009 - $282 million included in Accounts Receivable and Other). The loan, denominated in United States dollars, bears interest based on variable short-term rates.

During the year the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $40 million (US$39 million) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

**SPEARHEAD NORTH PIPELINE**
In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

**SOUTHERN LIGHTS PIPELINE**
In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 - $21 million) to the Company to lease Line 13.

**LONG-TERM RECEIVABLE FROM AFFILIATE**
An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million (2008 - $12 million).

**ENBRIDGE INCOME FUND HOLDINGS**
In December 2010, EIFH entered into an agreement with Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of the Company, to provide management and administrative services to EIFH. EMSI also provides management and administrative services to EIF. Provided that EIF is paying a base fee to EMSI for the services received by EIF, there is no fee payable to EMSI by EIFH as was the case for the period ended December 31, 2010.

**LAKEHEAD LINE 6B LEAK**
In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $18 million for the year ended December 31, 2010.

# 31. COMMITMENTS AND CONTINGENCIES

**COMMITMENTS**
The Company has signed contracts for the purchase of services, pipe and other materials totaling $1,686 million which are expected to be paid within the next 5 years.

**ENBRIDGE ENERGY PARTNERS, L.P.**
**EEP Lakehead System Line 6B and 6A Crude Oil Releases**
Enbridge holds an approximate 25.5% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

**Line 6B Leak**
On July 26, 2010, a crude oil release on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP currently estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. Regulatory approval of the pipeline restart plan was obtained from the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and, on September 27, 2010, the pipeline was safely brought back into service. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

EEP previously estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$430 million ($75 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), will be incurred in connection with this incident. These costs include emergency response, environmental remediation and cleanup activities associated with the crude oil release. EEP subsequently revised its estimate from US$430 million to US$550 million ($96 million after-tax net to Enbridge) based on a review of costs and commitments incurred, as well as additional information concerning the requirements for environmental restoration and remediation. The assumptions made including the scope of remediation efforts, the duration that resources will be required to complete the work, weather conditions and other similar factors underlying EEP's estimates are subject to further modification and could result in additional revisions to EEP's estimates. Although EEP met the deadlines established by the Environmental Protection Agency (EPA) for clean up and remediation of areas affected by the crude oil release, it has the potential of incurring additional costs in connection with this incident, including fines and penalties.

**Line 6A Leak**
A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP currently estimates that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release will be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge). Actual costs incurred may differ from the estimate due to variations in assumptions or in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

**Insurance Recoveries**

The Company maintains commercial liability insurance coverage that is consistent with coverage considered customary for its industry. The commercial liability insurance covers costs associated with environmental incidents such as those incurred for the leaks from Line 6B and 6A, excluding costs for fines and penalties. EEP is included in Enbridge's comprehensive insurance program that has an aggregate limit of US$650 million of pollution liability through the policy renewal date of May 1, 2011. The remaining coverage under the Company's existing insurance policies is approximately US$70 million. The Company does not maintain insurance coverage for interruption of operations except for water crossings; therefore, EEP will not recover approximately US$16 million of revenues lost while Line 6B and 6A were not in service. Apart from the amounts for which EEP is not insured, it is anticipated that substantially all of the costs incurred from the leaks will ultimately be recoverable under the Company's existing insurance policies. EEP expects to record a receivable for any amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery is probable.

**Pipeline Integrity Commitment**

In connection with the restart of Line 6B, EEP committed to accelerate a process, initiated prior to the leak, to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, EEP is remediating on schedule those pipeline anomalies it previously identified between 2007 and 2009 that were scheduled for refurbishment, including anomalies identified for action in a July 2010 PHMSA notification. EEP has agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. In addition to the required integrity measures, EEP also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. The total cost to EEP for these integrity measures and pipeline replacement are estimated to approximate US$110 million, the majority of which is expected to be capital in nature. Additional significant integrity expenditures may be required after this initial remediation program. EEP is currently discussing with its customers recovery of these costs through the tolls on its Lakehead System.

**Legal and Regulatory Proceedings**

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B incidents. Currently, approximately 20 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B incident; however, currently no penalties or fines have been assessed against EEP in connection with this incident. Currently, one action or claim related to the Line 6A incident has been filed against Enbridge, EEP or their affiliates in a United States state court. The Company believes this action or claim has been resolved pursuant to an agreed interim order.

**ENBRIDGE GAS DISTRIBUTION INC.**

**Bloor Street Incident**

EGD had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. EGD commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed EGD's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

**TAX MATTERS**
Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

**OTHER LITIGATION**
The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## 32. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:
- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:
- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

## 33. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

### EARNINGS

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Earnings under Canadian GAAP Applicable to Common Shareholders | **963** | 1,555 | 1,321 |
| Earnings under Canadian GAAP | **970** | 1,562 | 1,328 |
| Dilution gains, net of tax[1] | **(52)** | - | - |
| Gain on acquisition, net of tax[2] | **20** | - | - |
| Inventory valuation adjustment, net of tax[3] | **4** | (24) | - |
| Earnings/(Loss) attributable to non-controlling interests | | | |
| EEP[4] | **(172)** | 177 | 278 |
| Other[1,5] | **25** | 37 | 56 |
| Earnings under U.S. GAAP | **795** | 1,752 | 1,662 |
| Attributable to | | | |
| Enbridge Inc.[5] | **942** | 1,538 | 1,328 |
| Non-controlling interests[5] | **(147)** | 214 | 334 |
| Earnings under U.S. GAAP | **795** | 1,752 | 1,662 |
| Earnings per Common Share attributable to Enbridge Inc. | **2.55** | 4.71 | 3.67 |
| Diluted Earnings per Common Share attributable to Enbridge Inc. | **2.52** | 4.68 | 3.64 |

### COMPREHENSIVE INCOME

| Year ended December 31, | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Earnings under U.S. GAAP | **795** | 1,752 | 1,662 |
| Other comprehensive income/(loss) under Canadian GAAP | **(339)** | (576) | 318 |
| Underfunded pension adjustment, net of tax[6] | **(120)** | 3 | (57) |
| Other comprehensive income attributable to non-controlling interests under Canadian GAAP [5] | **(33)** | (72) | 101 |
| Other comprehensive loss attributable to non-controlling interests to non-controlling interest in EEP under U.S. GAAP[4] | **(29)** | (62) | 241 |
| Comprehensive income under U.S. GAAP | **274** | 1,045 | 2,265 |
| Attributable to | | | |
| Enbridge Inc.[5] | **483** | 965 | 1,589 |
| Non-controlling interests[5] | **(209)** | 80 | 676 |
| Comprehensive income under U.S. GAAP | **274** | 1,045 | 2,265 |

**FINANCIAL POSITION**

| December 31, | 2010 Canada | 2010 United States | 2009 Canada | 2009 United States |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| **Assets** | | | | |
| Current Assets | | | | |
| Cash and cash equivalents[4,7] | **242** | **387** | 327 | 478 |
| Accounts receivable and other[4,7] | **2,706** | **3,595** | 2,484 | 2,848 |
| Inventory[3,4,7] | **813** | **915** | 784 | 824 |
| | **3,761** | **4,897** | 3,595 | 4,150 |
| Property, Plant and Equipment, net[4,7] | **20,332** | **28,872** | 18,850 | 26,837 |
| Long-Term Investments[4,7] | **2,198** | **226** | 2,312 | 228 |
| Deferred Amounts and Other Assets[4,6,7,8] | **2,886** | **2,064** | 2,425 | 2,478 |
| Intangible Assets[4] | **478** | **753** | 488 | 575 |
| Goodwill[2,4] | **385** | **728** | 372 | 719 |
| Future Income Taxes[7] | **80** | **79** | 127 | 148 |
| | **30,120** | **37,619** | 28,169 | 35,135 |
| **Liabilities and Shareholders' Equity** | | | | |
| Current Liabilities | | | | |
| Short-term borrowings | **326** | **326** | 508 | 508 |
| Accounts payable and other[4,7] | **2,688** | **3,864** | 2,463 | 3,178 |
| Interest payable[4] | **117** | **177** | 104 | 151 |
| Current maturities of long-term debt[4] | **154** | **185** | 601 | 633 |
| Current maturities of non-recourse long-term debt[7] | **70** | **72** | 113 | 131 |
| | **3,355** | **4,624** | 3,789 | 4,601 |
| Long-Term Debt[4,7,8] | **13,561** | **18,403** | 11,866 | 15,932 |
| Non-Recourse Long-Term Debt[7] | **1,061** | **753** | 1,108 | 1,114 |
| Other Long-Term Liabilities[4,6,7] | **1,473** | **1,638** | 1,207 | 1,311 |
| Future Income Taxes[2,3,6] | **2,447** | **2,306** | 2,211 | 2,147 |
| | **21,897** | **27,724** | 20,181 | 25,105 |
| Non-Controlling Interests[5] | **658** | **-** | 727 | - |
| Shareholders' Equity | | | | |
| Share capital | | | | |
| Preferred shares | **125** | **125** | 125 | 125 |
| Common shares | **3,683** | **3,683** | 3,379 | 3,379 |
| Contributed surplus | **59** | **-** | 54 | - |
| Retained earnings | **4,734** | **4,648** | 4,400 | 4,343 |
| Additional paid in capital[1] | **-** | **103** | - | 98 |
| Accumulated other comprehensive loss[6] | **(882)** | **(1,105)** | (543) | (646) |
| Reciprocal shareholding | **(154)** | **(154)** | (154) | (154) |
| | **7,565** | **7,300** | 7,261 | 7,145 |
| Total Enbridge Inc. Liabilities and Shareholders' Equity | **30,120** | **35,024** | 28,169 | 32,250 |
| Non-Controlling Interests[5] | **-** | **2,595** | - | 2,885 |
| | **30,120** | **37,619** | 28,169 | 35,135 |

***1 Dilution Gains***

*Under Canadian GAAP, dilution gains are recorded as an increase to earnings. Under U.S. GAAP, dilution gains are recorded as equity transactions. During the year ended December 31, 2010, dilutions gains of $52 million, net of tax of $30 million, were reclassified from earnings to equity. The Company did not record any dilution gains during 2009. Prior to 2009 there was no recognition difference between Canadian and U.S. GAAP.*

***2 Gain on Acquisition***

*Under Canadian GAAP, the original equity interest in a step acquisition continues to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and non-controlling interest in a step acquisition are re-measured to fair value on the date control is obtained. Under Canadian GAAP, the original equity interest and non-controlling interest are not re-measured to fair value.*

*On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty Caverns was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of HardistyCaverns, a $20 million gain, net of tax, was recorded in earnings for the year ended December 31, 2010 under U.S GAAP.*

***3 Commodity Inventories Valuation***

*Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2010, lower of cost or market adjustments resulted in a $33 million (2009 - $36 million) decrease to inventory, a $12 million (2009 - $12 million) decrease to the future income tax liability and a $4 million increase (2009 - $24 million decrease) to earnings. There were no lower of cost or market adjustments related to commodity inventory valuation for the year ended December 31, 2008.*

***4 Consolidation of a Limited Partnership***

*Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 25.5% interest in the partnership, resulting in an increase to assets of $8,012 million (2009 - $6,974 million), an increase in liabilities of $6,131 million (2009 - $4,816) and an increase in non-controlling interests of $1,881 million (2009 - $2,158 million) at December 31, 2010 and no recognition or measurement changes to equity or earnings attributable to the Company as at and for the years ended December 31, 2010 and 2009.*

***5 Presentation of Non-Controlling Interests***

*Under Canadian GAAP earnings attributable to non-controlling interests are presented as part of earnings on the income statement and the non-controlling interest balance is presented outside of equity on the balance sheet. Under U.S. GAAP, the earnings and retained earnings attributable to non-controlling interests are presented as a separate component of equity.*

*For the year ended December 31, 2010, $147 million of losses (2009 - $214 million of earnings; 2008 - $334 million of earnings) are attributable to non-controlling interests.*

*Included in OCI for the year ended December 31, 2010 is an unrealized loss on cash flow hedges of $29 million (2009 - $62 million unrealized loss; 2008 - $241 million unrealized gain), and an after-tax change in OCI of $33 million (2009 - $1 million; 2008 - $20 million) attributable to non-controlling interests.*

***6 Pension Funding Status***

*U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through comprehensive income while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status.*

*Pension funding status adjustments resulted in an increase in the net liability of $338 million (2009 - $155 million) for the underfunded status of the plans, a decrease in future tax liability of $113 million (2009 - $52 million) and an increase in accumulated other comprehensive loss of $223 million (2009 - $103 million) at December 31, 2010.*

Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows:

| *(millions of Canadian dollars)* | **2010** | 2009 | 2008 |
|---|---|---|---|
| Prior service cost | **2** | 2 | 1 |
| Net transitional obligation | **(2)** | (1) | (1) |
| Net loss | **19** | 22 | 1 |
| | **19** | 23 | 1 |

Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:

| *(millions of Canadian dollars)* | **2010** | 2009 | 2008 |
|---|---|---|---|
| Prior service cost | **7** | 4 | 1 |
| Net transitional obligation | **(2)** | (3) | (6) |
| Accumulated net loss | **217** | 107 | 110 |
| | **222** | 108 | 105 |

Net amounts reflected in OCI for the year are as follows:

| *(millions of Canadian dollars)* | **2010** | 2009 | 2008 |
|---|---|---|---|
| Unamortized prior service cost | **3** | 3 | (3) |
| Unamortized transitional obligation | **1** | 3 | 1 |
| Net loss/(gain) | **111** | (3) | 58 |
| | **115** | 3 | 56 |

The Company estimates that approximately $17 million related to pension and OPEB plans at December 31, 2010 will be reclassified into earnings in the next twelve months, as follows:

| | Pension Benefits | OPEB | Total |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Net transitional obligation | (2) | 1 | (1) |
| Prior service costs | 1 | - | 1 |
| Loss | 16 | 1 | 17 |
| | 15 | 2 | 17 |

***7 Accounting for Joint Ventures***

*Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the United States Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.*

***8 Transaction Costs***

*Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-Term Debt. For U.S. GAAP, these costs are reclassified to Deferred Amounts and Other Assets. As at December 31, 2010, $89 million (2009 - $98 million) of transaction costs were reclassified.*

***9 Unrecognized Tax Benefits***

| | ***2010*** | *2009* |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| *Unrecognized Tax Benefits at beginning of year* | ***22*** | *13* |
| *Gross increases for tax positions of current year* | ***2*** | *5* |
| *Gross increases for tax positions of prior years* | ***-*** | *6* |
| *Gross decreases for tax positions of prior years* | ***(2)*** | *(1)* |
| *Reduction for lapse of statute of limitations* | ***(2)*** | *-* |
| *Changes in translation of foreign currency* | ***-*** | *(1)* |
| *Decreases relating to settlements with taxing authority* | ***(3)*** | *-* |
| *Unrecognized Tax Benefits at end of year* | ***17*** | *22* |

*The unrecognized tax benefits at December 31, 2010, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.*

*The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2010 includes a recovery of $2 million (2009 - $1 million expense) of interest and penalties. As at December 31, 2010, interest and penalties of $8 million (2009 - $10 million) have been accrued.*

*The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007 and all returns are generally closed through 2005. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2006, with the exception of years under adjustment relating to the 2008 unfavourable court decision.*

***10 Indefinite Reversal Rule***

*The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2010 were approximately $491 million (2009 - $460 million).*

## FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2011. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

### Fair Value Measurements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements.* The ASU updates the current authoritative guidance pertaining to fair value measurements by enhancing existing disclosure requirements for both the valuation techniques and inputs used to determine fair value measurements.

### Stock-Based Compensation

In April 2010, the FASB issued ASU No. 2010-13, *Compensation – Stock Compensation (Topic 718): Effect of Denominating the Exercise Price of a Share-Based Payment Award in the Currency of the Market in Which the Underlying Equity Security Trades.* The ASU updates the current authoritative guidance pertaining to stock-based compensation by clarifying the classification of an employee share-based payment award with an exercise price denominated in the currency of a market in which the underlying equity trades.

### Goodwill and Intangibles

In December 2010, the FASB issued ASU No. 2010-28, *Intangibles – Goodwill and Other (Topic 350) – When to perform step 2 of the goodwill impairment test for reporting units with zero or negative carrying value*. This ASU updates the current authoritative guidance pertaining to goodwill impairment testing by modifying step one of the goodwill impairment test for reporting units with zero or negative carrying amounts requiring the performance of step two if it is more likely than not that a goodwill impairment exists.

### Business Combinations

In December 2010, the FASB issued ASU No. 2010-29, *Business Combinations (Topic 805) – Disclosure of Supplementary Pro Forma Information for Business Combinations*. This ASU updates the current authoritative guidance pertaining to the disclosure requirements for a business combination by clarifying and expanding the existing requirements related to pro forma revenue and earnings.




# ENBRIDGE INC.

# CONSOLIDATED FINANCIAL STATEMENTS

## December 31, 2011

# MANAGEMENT'S REPORT

## To the Shareholders of Enbridge Inc.

**Financial Reporting**
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

**Internal Control over Financial Reporting**
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).

"signed"

**Patrick D. Daniel**
President & Chief Executive Officer

"signed"

**J. Richard Bird**
Executive Vice President &
Chief Financial Officer

February 21, 2012



**Independent Auditor's Report**

**To the Shareholders of Enbridge Inc.**

We have completed integrated audits of Enbridge Inc.'s 2011, 2010 and 2009 consolidated financial statements and its internal control over financial reporting as at December 31, 2011. Our opinions, based on our audits, are presented below.

**Report on the consolidated financial statements**
We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2011 and December 31, 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the consolidated financial statements**
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's responsibility**
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

**Opinion**
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

**Report on internal control over financial reporting**
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2011, based on the criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

*PricewaterhouseCoopers LLP, Chartered Accountants*
*111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3*
*T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca*

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

**Management's responsibility for internal control over financial reporting**
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

**Auditor's responsibility**
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

**Definition of internal control over financial reporting**
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

**Inherent limitations**
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

**Opinion**
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2011 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

**Chartered Accountants**
Calgary, Alberta, Canada

February 21, 2012

# CONSOLIDATED STATEMENTS OF EARNINGS

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Revenues | | | |
| Commodity sales | **15,676** | 11,990 | 9,720 |
| Transportation and other services | **3,726** | 3,137 | 2,746 |
| | **19,402** | 15,127 | 12,466 |
| Expenses | | | |
| Commodity costs | **14,854** | 11,291 | 9,011 |
| Operating and administrative | **1,720** | 1,466 | 1,430 |
| Depreciation and amortization | **937** | 864 | 764 |
| | **17,511** | 13,621 | 11,205 |
| | **1,891** | 1,506 | 1,261 |
| Income from equity investments | **336** | 38 | 198 |
| Other income *(Note 28)* | **112** | 374 | 678 |
| Interest expense *(Note 16)* | **(711)** | (687) | (597) |
| Gain on sale of investments *(Note 6)* | **-** | - | 365 |
| | **1,628** | 1,231 | 1,905 |
| Income taxes *(Note 26)* | **(568)** | (251) | (306) |
| Earnings | **1,060** | 980 | 1,599 |
| Earnings attributable to noncontrolling interests | **(56)** | (10) | (37) |
| Earnings attributable to Enbridge Inc. | **1,004** | 970 | 1,562 |
| Preference share dividends | **(13)** | (7) | (7) |
| Earnings attributable to Enbridge Inc. common shareholders | **991** | 963 | 1,555 |
| Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)* | **1.32** | 1.30 | 2.14 |
| Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)* | **1.30** | 1.29 | 2.12 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings | **1,060** | 980 | 1,599 |
| Other comprehensive income/(loss) | | | |
| Change in unrealized loss on cash flow hedges, net of tax | **(427)** | (113) | (54) |
| Change in unrealized gain/(loss) on net investment hedges, net of tax | **(19)** | 51 | 151 |
| Reclassification to earnings of realized cash flow hedges, net of tax | **32** | (25) | 114 |
| Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 23)* | **8** | - | (20) |
| Other comprehensive loss from equity investees, net of tax | **(61)** | (11) | (24) |
| Change in foreign currency translation adjustment | **242** | (274) | (815) |
| Other comprehensive loss | **(225)** | (372) | (648) |
| Comprehensive income | **835** | 608 | 951 |
| Comprehensive (income)/loss attributable to noncontrolling interests | **(43)** | 23 | 35 |
| Comprehensive income attributable to Enbridge Inc. | **792** | 631 | 986 |
| Preference share dividends | **(13)** | (7) | (7) |
| Comprehensive income attributable to Enbridge Inc. common shareholders | **779** | 624 | 979 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Preference shares *(Note 20)* | | | |
| Balance at beginning of year | **125** | 125 | 125 |
| Preference shares issued | **931** | - | - |
| Balance at end of year | **1,056** | 125 | 125 |
| Common shares *(Note 20)* | | | |
| Balance at beginning of year | **3,683** | 3,379 | 3,194 |
| Common shares issued | **-** | - | 4 |
| Dividend reinvestment and share purchase plan | **229** | 224 | 143 |
| Shares issued on exercise of stock options | **57** | 80 | 38 |
| Balance at end of year | **3,969** | 3,683 | 3,379 |
| Contributed surplus | | | |
| Balance at beginning of year | **59** | 54 | 38 |
| Stock-based compensation | **18** | 13 | 19 |
| Options exercised | **(7)** | (8) | (3) |
| Dilution gains and other *(Note 19)* | **36** | - | - |
| Balance at end of year | **106** | 59 | 54 |
| Retained earnings | | | |
| Balance at beginning of year | **4,734** | 4,400 | 3,383 |
| Earnings attributable to Enbridge Inc. common shareholders | **991** | 963 | 1,555 |
| Common share dividends declared | **(759)** | (648) | (555) |
| Dividends paid to reciprocal shareholder | **25** | 19 | 17 |
| Balance at end of year | **4,991** | 4,734 | 4,400 |
| Accumulated other comprehensive income/(loss) *(Note 22)* | | | |
| Balance at beginning of year | **(882)** | (543) | 33 |
| Other comprehensive loss | **(212)** | (339) | (576) |
| Balance at end of year | **(1,094)** | (882) | (543) |
| Reciprocal shareholding *(Note 11)* | | | |
| Balance at beginning of year | **(154)** | (154) | (154) |
| Acquisition of equity investment | **(33)** | - | - |
| Balance at end of year | **(187)** | (154) | (154) |
| Total Enbridge Inc. shareholders' equity | **8,841** | 7,565 | 7,261 |
| Noncontrolling interests | | | |
| Balance at beginning of year | **658** | 727 | 797 |
| Earnings attributable to noncontrolling interests | **56** | 10 | 37 |
| Other comprehensive income/(loss) attributable to noncontrolling interests | | | |
| Change in unrealized income/(loss) on cash flow hedges, net of tax | **(7)** | (9) | 4 |
| Other comprehensive loss from equity investees, net of tax | **(15)** | (3) | (5) |
| Change in foreign currency translation adjustment | **9** | (21) | (71) |
| | **(13)** | (33) | (72) |
| Comprehensive income/(loss) attributable to noncontrolling interests | **43** | (23) | (35) |
| Distributions | **(37)** | (30) | (33) |
| Contributions *(Note 19)* | **208** | 29 | - |
| Acquisitions *(Notes 10 and 19)* | **(27)** | (45) | - |
| Other | **1** | - | (2) |
| Balance at end of year | **846** | 658 | 727 |
| Total shareholders' equity | **9,687** | 8,223 | 7,988 |
| Dividends paid per common share | **0.98** | 0.85 | 0.74 |

*The accompanying notes are an integral part of these consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Operating activities** | | | |
| Earnings attributable to Enbridge Inc. | **1,004** | 970 | 1,562 |
| Depreciation and amortization | **937** | 864 | 764 |
| Unrealized gains on derivative instruments | **(13)** | (10) | (204) |
| Allowance for equity funds used during construction | **(3)** | (80) | (135) |
| Cash distributions (less than)/in excess of equity earnings | **(42)** | 214 | (9) |
| Gain on reduction of ownership interest | **(141)** | (81) | - |
| Gain on sale of investments *(Note 6)* | **-** | - | (365) |
| Future income taxes *(Note 26)* | **415** | 238 | 218 |
| Goodwill and asset impairment losses | **11** | - | 11 |
| Noncontrolling interests | **56** | 10 | 37 |
| Other | **150** | (11) | (105) |
| Changes in regulatory assets and liabilities | **78** | 30 | 11 |
| Changes in operating assets and liabilities *(Note 29)* | **251** | (293) | 232 |
| | **2,703** | 1,851 | 2,017 |
| **Investing activities** | | | |
| Additions to property, plant and equipment | **(2,516)** | (2,357) | (3,225) |
| Government grant | **145** | - | - |
| Additions to intangible assets | **(165)** | (50) | (95) |
| Change in construction payable | **(66)** | 27 | (110) |
| Long-term investments | **(217)** | (121) | (359) |
| Affiliate loans, net | **10** | (80) | (145) |
| Acquisitions *(Notes 6 and 19)* | **(1,208)** | (116) | - |
| Proceeds on sale of investments *(Note 6)* | **-** | 23 | 535 |
| Sale of property, plant and equipment | **-** | - | 87 |
| Settlement of hedges *(Note 6)* | **-** | - | 6 |
| | **(4,017)** | (2,674) | (3,306) |
| **Financing activities** | | | |
| Net change in bank indebtedness and short-term borrowings | **224** | (165) | (393) |
| Net change in commercial paper and credit facility draws | **11** | (347) | 736 |
| Debenture and term note issues | **825** | 2,300 | 1,500 |
| Debenture and term note repayments | **(203)** | (600) | (616) |
| Net change in Southern Lights project financing | **(62)** | 14 | 343 |
| Non-recourse debt issues | **17** | 5 | 60 |
| Non-recourse debt repayments | **(81)** | (73) | (130) |
| Contributions from/(distributions) to noncontrolling interests, net | **214** | (1) | (33) |
| Preference shares issued | **926** | - | - |
| Common shares issued | **46** | 66 | 36 |
| Preference share dividends | **(7)** | (7) | (7) |
| Common share dividends | **(530)** | (426) | (414) |
| | **1,380** | 766 | 1,082 |
| Effect of translation of foreign denominated cash and cash equivalents | **12** | (11) | (35) |
| Increase/(decrease) in cash and cash equivalents | **78** | (68) | (242) |
| Cash and cash equivalents at beginning of year | **342** | 410 | 652 |
| **Cash and cash equivalents at end of year**[1] | **420** | 342 | 410 |
| | | | |
| **Supplementary cash flow information** | | | |
| Income taxes paid/(received) *(Note 26)* | **(35)** | 108 | 205 |
| Interest paid *(Note 16)* | **749** | 711 | 656 |

*The accompanying notes are an integral part of these consolidated financial statements.*

1 *Cash and cash equivalents consists of $343 million (2010 - $243 million; 2009 - $267 million) of cash and $77 million (2010 - $99 million; 2009 - $143 million) of short-term investments and includes restricted cash of $17 million (2010 - $12 million; 2009 - $7 million), and joint-venture cash which is not readily accessible by the Company of $224 million (2010 - $48 million; 2009 - $52 million).*

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | **420** | 342 |
| Accounts receivable and other *(Note 7)* | **3,136** | 2,706 |
| Inventory *(Note 8)* | **739** | 813 |
| | **4,295** | 3,861 |
| Property, plant and equipment, net *(Note 9)* | **22,623** | 20,332 |
| Long-term investments *(Note 11)* | **2,540** | 2,198 |
| Deferred amounts and other assets *(Note 12)* | **3,220** | 2,886 |
| Intangible assets *(Note 13)* | **600** | 478 |
| Goodwill *(Note 14)* | **1,024** | 385 |
| Future income taxes *(Note 26)* | **41** | 80 |
| | **34,343** | 30,220 |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | | |
| Bank indebtedness | **102** | 100 |
| Short-term borrowings *(Note 16)* | **548** | 326 |
| Accounts payable and other *(Note 15)* | **3,722** | 2,688 |
| Interest payable | **114** | 117 |
| Current maturities of long-term debt *(Note 16)* | **252** | 154 |
| Current maturities of non-recourse long-term debt *(Note 17)* | **122** | 70 |
| | **4,860** | 3,455 |
| Long-term debt *(Note 16)* | **14,257** | 13,561 |
| Non-recourse long-term debt *(Note 17)* | **951** | 1,061 |
| Other long-term liabilities *(Note 18)* | **1,892** | 1,473 |
| Future income taxes *(Note 26)* | **2,696** | 2,447 |
| | **24,656** | 21,997 |
| Equity | | |
| Share capital | | |
| Preference shares *(Note 20)* | **1,056** | 125 |
| Common shares *(Note 20)* | **3,969** | 3,683 |
| Contributed surplus | **106** | 59 |
| Retained earnings | **4,991** | 4,734 |
| Accumulated other comprehensive loss *(Note 22)* | **(1,094)** | (882) |
| Reciprocal shareholding *(Note 11)* | **(187)** | (154) |
| Total Enbridge Inc. shareholders' equity | **8,841** | 7,565 |
| Noncontrolling interests *(Note 19)* | **846** | 658 |
| | **9,687** | 8,223 |
| Commitments and contingencies *(Note 31)* | | |
| | **34,343** | 30,220 |

*The accompanying notes are an integral part of these consolidated financial statements.*

Approved by the Board of Directors:

| | |
|---|---|
| "signed" | "signed" |
| **David A. Arledge** | **David A. Leslie** |
| Chair | Director |

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

## 1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

**LIQUIDS PIPELINES**
Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including the Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

**GAS DISTRIBUTION**
Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

**GAS PIPELINES, PROCESSING AND ENERGY SERVICES**
Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business, an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico System. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

**SPONSORED INVESTMENTS**
Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

**CORPORATE**
Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

# 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post-employment benefits *(Note 27)*; commitments and contingencies *(Note 31);* and fair value of asset retirement obligations (AROs). Actual results could differ from these estimates.

**BASIS OF PRESENTATION**

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and its proportionate share of the accounts of various joint ventures. The Fund is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of the Fund through the combination of a total direct and indirect 35.4% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to maturity, Loans and receivables or Available for sale (see *Financial Instruments*).

**REGULATION**

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the

capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

**REVENUE RECOGNITION**

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue was recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Effective July 1, 2011, Canadian Mainline earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective July 1, 2011, the Company discontinued the application of rate-regulated accounting for its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis, with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

For rate-regulated operations in Sponsored Investments and rate-regulated operations in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

**FINANCIAL INSTRUMENTS**

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the Consolidated Statements of Financial Position. Subsequent measurement of the financial instrument is based on its classification.

**Held for Trading**

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenue, Commodity costs, Other income and Interest expense. The Company has classified Cash and cash equivalents, bank indebtedness and its non-qualifying derivative instruments as held for trading.

**Available for Sale**
Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other comprehensive income/(loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from available for sale financial assets are recognized in earnings when the right to receive payment is established.

**Loans and Receivables**
Loans and receivables, which include Accounts receivable and other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

**Held to Maturity**
The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

**Other Financial Liabilities**
Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Interest payable, Long-term debt and Non-recourse long-term debt.

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges
The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Fair Value Hedges
The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges outstanding at December 31, 2011 or December 31, 2010.

**Net Investment Hedges**
The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment.

**Classification of Derivatives**
The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current or long-term depending on the timing of the settlements and the resulting cash flows associated with the instruments. The fair value related to cash flows occurring beyond one year are classified as non-current.

**Balance Sheet Offset**
Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

**Transaction Costs**
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

**EQUITY INVESTMENTS**
Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

**NONCONTROLLING INTERESTS**
Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and variable interest entities. The portion of the entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

**INCOME TAXES**
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a future income tax liability is recognized with a corresponding regulatory asset. Any interest and/or penalty incurred related to tax is reflected in income taxes.

**FOREIGN CURRENCY TRANSLATION**
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates. Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these

operations are included in the cumulative translation adjustment component of AOCI and are recognized in earnings when there is a disposal of all or part of the foreign operation.

**CASH AND CASH EQUIVALENTS**
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

**ALLOWANCE FOR DOUBTFUL ACCOUNTS**
The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

**INVENTORY**
Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

**PROPERTY, PLANT AND EQUIPMENT**
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

The Company uses the group method of depreciation for all property, plant and equipment, except for the non rate-regulated assets in Canada, which are depreciated on a single asset basis. Depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Under the group method, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, a gain or loss is recognized in the Consolidated Statements of Earnings for the difference between the cash received and the net book value of the assets sold.

**DEFERRED AMOUNTS AND OTHER ASSETS**
Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including future income taxes, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

**INTANGIBLE ASSETS**
Intangible assets consist primarily of acquired long-term transportation contracts, long-term power purchase agreements and certain software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangibles are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

**GOODWILL**
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually in the fourth quarter of each year, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment.

Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

**IMPAIRMENT**

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

**ASSET RETIREMENT OBLIGATIONS**

AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

**POST-EMPLOYMENT BENEFITS**

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

Certain regulated operations of the Company recover pension and OPEB expense based on amounts paid in accordance with the methodology accepted by the regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. In the absence of rate regulation, these balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.

**STOCK BASED COMPENSATION**
Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Contributed surplus. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Bloomberg barrier option valuation model and is recognized on a straight-line basis with a corresponding credit to Contributed surplus. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

**COMPARATIVE AMOUNTS**
Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

## 3. CHANGES IN ACCOUNTING POLICIES

**Business Combinations**
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect

a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

**Consolidated Financial Statements and Noncontrolling Interests**
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements* and 1602, *Noncontrolling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there was no impact to the Company's earnings or cash flow for the current or prior periods presented.

**United States Generally Accepted Accounting Principles**
First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

# 4. SEGMENTED INFORMATION

| **Year ended December 31, 2011** | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | **1,959** | **2,574** | **14,476** | **393** | **-** | **19,402** |
| Commodity costs | **-** | **(1,354)** | **(13,500)** | **-** | **-** | **(14,854)** |
| Operating and administrative | **(760)** | **(492)** | **(295)** | **(137)** | **(36)** | **(1,720)** |
| Depreciation and amortization | **(327)** | **(320)** | **(167)** | **(111)** | **(12)** | **(937)** |
| | **872** | **408** | **514** | **145** | **(48)** | **1,891** |
| Income/(loss) from equity investments | **-** | **-** | **-** | **342** | **(6)** | **336** |
| Other income/(expense) | **31** | **(11)** | **38** | **202** | **(148)** | **112** |
| Interest expense | **(256)** | **(166)** | **(97)** | **(74)** | **(118)** | **(711)** |
| Income taxes recovery/(expense) | **(139)** | **(55)** | **(161)** | **(219)** | **6** | **(568)** |
| Earnings/(loss) | **508** | **176** | **294** | **396** | **(314)** | **1,060** |
| Earnings attributable to noncontrolling interests | **(3)** | **-** | **(1)** | **(52)** | **-** | **(56)** |
| Preference share dividends | **-** | **-** | **-** | **-** | **(13)** | **(13)** |
| Earnings/(loss) attributable to Enbridge Inc. common shareholders | **505** | **176** | **293** | **344** | **(327)** | **991** |
| Additions to property, plant and equipment[1] | **977** | **483** | **953** | **73** | **33** | **2,519** |
| Total assets | **12,366** | **7,713** | **4,968** | **5,245** | **4,051** | **34,343** |

| Year ended December 31, 2010 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | 1,672 | 2,611 | 10,518 | 326 | - | 15,127 |
| Commodity costs | - | (1,384) | (9,907) | - | - | (11,291) |
| Operating and administrative | (603) | (497) | (215) | (120) | (31) | (1,466) |
| Depreciation and amortization | (312) | (310) | (144) | (88) | (10) | (864) |
| | 757 | 420 | 252 | 118 | (41) | 1,506 |
| Income from equity investments | - | - | - | 32 | 6 | 38 |
| Other income/(expense) | 115 | (17) | 30 | 114 | 132 | 374 |
| Interest expense | (223) | (179) | (96) | (58) | (131) | (687) |
| Income taxes recovery/(expense) | (135) | (64) | (65) | (66) | 79 | (251) |
| Earnings | 514 | 160 | 121 | 140 | 45 | 980 |
| Earnings attributable to noncontrolling interests | (2) | (5) | - | (3) | - | (10) |
| Preference share dividends | - | - | - | - | (7) | (7) |
| Earnings attributable to Enbridge Inc. common shareholders | 512 | 155 | 121 | 137 | 38 | 963 |
| Additions to property, plant and equipment[1] | 765 | 387 | 1,153 | 132 | - | 2,437 |
| Total assets | 11,508 | 7,594 | 5,536 | 3,833 | 1,749 | 30,220 |

| Year ended December 31, 2009 | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Revenues | 1,333 | 2,992 | 7,823 | 313 | 5 | 12,466 |
| Commodity costs | - | (1,757) | (7,254) | - | - | (9,011) |
| Operating and administrative | (565) | (495) | (226) | (113) | (31) | (1,430) |
| Depreciation and amortization | (230) | (298) | (140) | (88) | (8) | (764) |
| | 538 | 442 | 203 | 112 | (34) | 1,261 |
| Income from equity investments | - | - | - | 188 | 10 | 198 |
| Other income/(expense) and gain on sale of investments | 161 | (12) | 366 | 13 | 515 | 1,043 |
| Interest expense | (144) | (188) | (87) | (56) | (122) | (597) |
| Income taxes | (108) | (50) | (54) | (88) | (6) | (306) |
| Earnings | 447 | 192 | 428 | 169 | 363 | 1,599 |
| Earnings attributable to noncontrolling interests | (2) | (6) | - | (28) | (1) | (37) |
| Preference share dividends | - | - | - | - | (7) | (7) |
| Earnings attributable to Enbridge Inc. common shareholders | 445 | 186 | 428 | 141 | 355 | 1,555 |
| Additions to property, plant and equipment[1] | 2,662 | 326 | 321 | 41 | 10 | 3,360 |

*1 Includes allowance for equity funds used during construction (AEDC).*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

**GEOGRAPHIC INFORMATION**

**Revenues[1]**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Canada | **12,591** | 9,876 | 9,503 |
| United States | **6,811** | 5,251 | 2,963 |
| | **19,402** | 15,127 | 12,466 |

*1 Revenues are based on the country of origin of the product or services sold.*

**Property, Plant and Equipment**

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canada | **17,843** | 16,095 |
| United States | **4,780** | 4,237 |
| | **22,623** | 20,332 |

# 5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

**GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS**

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

**Canadian Mainline**

The Canadian Mainline includes the Canadian portion of the mainline system. The primary business activities of the Canadian Mainline are subject to regulation by the NEB. Prior to July 1, 2011, the incentive tolling settlement (ITS) defined the methodology for calculation of tolls and the revenue requirement on the core component of the Canadian Mainline. Toll adjustments, for variances from requirements defined in the ITS, were filed annually with the regulator for approval. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Effective July 1, 2011, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the ten year term of the CTS. As a result, the Company discontinued the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost of service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment.

The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the discontinuance of rate-regulated accounting, and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. The regulatory asset of approximately $70 million related to tolling deferrals recorded at the date of discontinuance is being recovered through a toll surcharge over a period of two years.

**Southern Lights**
The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

**Enbridge Gas Distribution**
EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2011, 2010 and 2009 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

**Enbridge Gas New Brunswick**
Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE for the year ended December 31, 2011 was 10.90% (2010 - 13.00%; 2009 - 13.00%) based on equity which is capped at 45%.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

**Vector Pipeline**
Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2011 included an after-tax ROE component of 11.18% (2010 - 11.18%; 2009 - 11.07%).

**Alliance Pipeline**

The Alliance Pipeline US is regulated by the FERC and Alliance Pipeline Canada is regulated by the NEB. Transportation service agreements with shippers are in place for substantially all of the pipeline capacity until December 2015 under a cost of service methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2011, 2010 and 2009 included an after-tax ROE component of 10.88% for Alliance Pipeline US and 11.26% (2010 - 11.26%; 2009 - 11.26%) for Alliance Pipeline Canada. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

**FINANCIAL STATEMENT EFFECTS**

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

| December 31, | **2011** | 2010 | Estimated Settlement Period *(years)* | Earnings Impact[1] **2011** | 2010 | 2009 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| **Regulatory assets/(liabilities)** | | | | | | |
| Liquids Pipelines | | | | | | |
| Future income taxes[2] | **527** | 479 | - | **36** | 55 | 49 |
| Tolling deferrals[3] | **14** | 132 | 1 | **(3)** | 19 | (16) |
| Deferred transportation revenue[8] | **84** | 32 | 29 | **34** | 21 | - |
| Gas Distribution | | | | | | |
| Future income taxes[2] | **224** | 211 | - | **9** | (12) | (11) |
| EGNB regulatory deferral[4] | **180** | 171 | 30 | **9** | 18 | 15 |
| Future removal and site restoration reserves[5] | **(836)** | (773) | - | **-** | - | 6 |
| Purchased gas variance[6] | **-** | (144) | 1 | **-** | - | - |
| Pension plans and OPEB, net[7] | **(95)** | (97) | - | **(2)** | - | (2) |
| Gas Pipelines, Processing and Energy Services | | | | | | |
| Future income taxes[2] | **1** | 1 | - | **-** | - | - |
| Deferred transportation revenue[8] | **124** | 150 | 13-15 | **(18)** | (17) | (6) |
| Sponsored Investments | | | | | | |
| Future income taxes[2] | **83** | 94 | - | **(8)** | (3) | (11) |
| Deferred transportation revenue[8] | **100** | 98 | 15 | **1** | 5 | 5 |

1 *The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

2 *The asset represents the regulatory offset to future income tax liabilities to the extent that future income taxes are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *Tolls for regulated pipelines under a cost of service methodology are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline result in an under or over collection of the annual revenue requirement, a regulatory asset or liability is recognized and incorporated into tolls in the subsequent year or in accordance with the related agreement.*

4 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end no sooner than 2040. The impact of legislative changes passed by the Government of New Brunswick in December 2011 (the specific details of which remain dependent upon regulations which have not yet been published) is not determinable as of February 21, 2012.*

5 *The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company's businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

6 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.*

7 *The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

8 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Southern Lights, Alliance and Vector Pipelines and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Southern Lights after 2020, for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.*

**OTHER ITEMS AFFECTED BY RATE REGULATION**

**Allowance for Funds Used During Construction and Other Capitalized Costs**

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

**Operating Cost Capitalization**

With the approval of regulators, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, cumulative costs relating to this consulting contract of $133 million (2010 - $124 million) were included in property plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

# 6. ACQUISITIONS AND DISPOSITIONS

**ACQUISITIONS**

**Seaway Crude Pipeline Company**

On December 20, 2011, Enbridge acquired 50% of the outstanding common units in Seaway Pipeline, a partnership engaged in the crude oil pipeline business in Texas, for cash consideration of $1.2 billion (US$1.2 billion). The Company's investment in Seaway Pipeline is accounted for as a joint venture interest *(Note 10)*.

| December 20, | **2011** |
|---|---|
| *(millions of Canadian dollars)* | |
| Fair value of net assets acquired: | |
| Current assets | **5** |
| Property, plant and equipment | **536** |
| Goodwill | **638** |
| Current liabilities | **(4)** |
| | **1,175** |
| Purchase Price: | |
| Cash (net of $9 million cash acquired) | **1,175** |

A net loss of $1 million related to transaction costs was recognized in Earnings for the year ended December 31, 2011. Had the acquisition occurred on January 1, 2011, an unaudited proforma net loss of $2 million, including $1 million of transaction costs, would have been recognized as earnings. The entire amount of acquired goodwill is expected to be tax deductible for United States income tax purposes.

**Tonbridge Power Inc.**
On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share.

| October 13, | **2011** |
|---|---|
| *(millions of Canadian dollars)* | |
| Fair value of net assets acquired: | |
| Working capital deficiency | **(5)** |
| Property, plant and equipment | **196** |
| Intangible assets | **17** |
| Long-term debt | **(182)** |
| Other long-term liabilities | **(21)** |
| | **5** |
| Purchase Price: | |
| Cash (net of $15 million cash acquired) | **5** |

No revenue from Tonbridge was recognized in 2011 as the transmission line is not yet in service. A net loss of $1 million was recognized in income for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expenses. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in income in 2011 had the acquisition occurred on January 1, 2011.

**DISPOSITIONS**
**Gain on Sale of Investments**

| December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| NetThruPut (NTP) | - | **-** | 29 |
| Oleoducto Central S.A. (OCENSA) | - | **-** | 336 |
| | - | **-** | 365 |

**NTP**
On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million and were included in the Corporate operating segment.

**OCENSA**
On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million. Earnings from the OCENSA investment were included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

## 7. ACCOUNTS RECEIVABLE AND OTHER

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Unbilled revenues | **1,535** | 1,284 |
| Trade receivables | **699** | 740 |
| Taxes receivable | **157** | 205 |
| Regulatory assets | **80** | 182 |
| Current derivative assets *(Note 23)* | **465** | 170 |
| Due from affiliates *(Note 30)* | **69** | 63 |
| Prepaid expenses and deposits | **42** | 36 |
| Dividends receivable | **32** | 16 |
| Other | **113** | 72 |
| Allowance for doubtful accounts *(Note 23)* | **(56)** | (62) |
| | **3,136** | 2,706 |

## 8. INVENTORY

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Natural gas | **488** | 537 |
| Other commodities | **251** | 276 |
| | **739** | 813 |

# 9. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2011<br>*(millions of Canadian dollars)* | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| Liquids Pipelines | | | | |
| Pipeline | 2.8% | **7,482** | **1,811** | **5,671** |
| Pumping equipment, buildings, tanks and other | 3.5% | **5,098** | **1,367** | **3,731** |
| Land and right-of-way | 3.0% | **232** | **38** | **194** |
| Under construction | - | **1,718** | **-** | **1,718** |
| | | **14,530** | **3,216** | **11,314** |
| Gas Distribution | | | | |
| Gas mains, services and other | 4.0% | **6,961** | **1,401** | **5,560** |
| Land and right-of-way | 2.5% | **79** | **30** | **49** |
| Under construction | - | **137** | **-** | **137** |
| | | **7,177** | **1,431** | **5,746** |
| Gas Pipelines, Processing and Energy Services | | | | |
| Pipeline | 3.6% | **2,171** | **814** | **1,357** |
| Wind turbines, solar panels and other[1] | 5.8% | **1,208** | **125** | **1,083** |
| Land and right-of-way | 2.6% | **50** | **14** | **36** |
| Under construction | - | **567** | **-** | **567** |
| | | **3,996** | **953** | **3,043** |
| Sponsored Investments | | | | |
| Pipeline | 4.0% | **1,105** | **398** | **707** |
| Wind turbines, solar panels and other[1] | 3.4% | **1,744** | **225** | **1,519** |
| Under construction | - | **23** | **-** | **23** |
| | | **2,872** | **623** | **2,249** |
| Corporate | | | | |
| Other | 2.9% | **270** | **30** | **240** |
| Under construction | - | **31** | **-** | **31** |
| | | **301** | **30** | **271** |
| | | **28,876** | **6,253** | **22,623** |

| December 31, 2010 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | | | | |
| Pipeline | 2.7% | 7,295 | 1,618 | 5,677 |
| Pumping equipment, buildings, tanks and other | 3.6% | 4,728 | 1,221 | 3,507 |
| Land and right-of-way | 1.8% | 232 | 29 | 203 |
| Under construction | - | 728 | - | 728 |
| | | 12,983 | 2,868 | 10,115 |
| Gas Distribution | | | | |
| Gas mains, services and other | 3.6% | 6,605 | 1,272 | 5,333 |
| Land and right-of-way | 2.6% | 68 | 15 | 53 |
| Under construction | - | 103 | - | 103 |
| | | 6,776 | 1,287 | 5,489 |
| Gas Pipelines, Processing and Energy Services | | | | |
| Pipeline | 3.4% | 2,121 | 706 | 1,415 |
| Wind turbines, solar panels and other[1] | 3.1% | 1,527 | 142 | 1,385 |
| Land and right-of-way | 2.4% | 62 | 13 | 49 |
| Under construction | - | 622 | - | 622 |
| | | 4,332 | 861 | 3,471 |
| Sponsored Investments | | | | |
| Pipeline | 4.0% | 1,598 | 484 | 1,114 |
| Wind turbines, solar panels and other[1] | 8.5% | 108 | 29 | 79 |
| Under construction | - | 17 | - | 17 |
| | | 1,723 | 513 | 1,210 |
| Corporate | | | | |
| Other | 11.3% | 67 | 20 | 47 |
| | | 67 | 20 | 47 |
| | | 25,881 | 5,549 | 20,332 |

1 *In October 2011, Enbridge Pipelines Inc. (EPI) sold three renewable energy assets to the Fund. As a result, at December 31, 2011, $1,087 million of property, plant and equipment was reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The December 31, 2010 balance of $1,103 million has not been reclassified for presentation purposes.*

# 10. JOINT VENTURES

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

| December 31, | Ownership Interest | Net Assets **2011** | 2010 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Liquids Pipelines | | | |
| Chicap Pipeline | 43.8% | **27** | 27 |
| Mustang Pipeline | 30.0% | **27** | 26 |
| Woodland Pipeline | 50.0% | **79** | 23 |
| Seaway Pipeline *(Note 6)* | 50.0% | **1,186** | - |
| Gas Pipelines, Processing and Energy Services | | | |
| Enbridge Offshore Pipelines - various joint ventures | 22.0%-74.3% | **420** | 433 |
| Alliance Pipeline US | 50.0% | **293** | 318 |
| Vector Pipeline | 60.0% | **347** | 349 |
| Aux Sable[1] | 42.7%-50.0% | **217** | 86 |
| Lac Alfred Wind Project (Lac Alfred)[2] | 50.0% | **130** | - |
| Other | 33.3%-70.0% | **21** | 27 |
| Sponsored Investments | | | |
| Alliance Pipeline Canada | 50.0% | **642** | 660 |
| Other | 33.0%-50.0% | **58** | 56 |
| | | **3,447** | 2,005 |

*1 In July 2011, the Company, through its affiliate Aux Sable, acquired a 42.7% interest in the Palermo Conditioning Plant and the Prairie Rose Pipeline for $76 million.*

*2 In December 2011, the Company acquired a 50% interest in the Lac Alfred for $128 million.*

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company.

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings | | | |
| Revenues | **804** | 771 | 781 |
| Commodity costs | **(138)** | (92) | (74) |
| Operating and administrative | **(200)** | (203) | (226) |
| Depreciation and amortization | **(163)** | (163) | (171) |
| Interest expense | **(75)** | (82) | (99) |
| Other income/(expense) | **(2)** | (1) | 10 |
| Proportionate share of earnings | **226** | 230 | 221 |
| Cash flows | | | |
| Cash provided by operating activities | **392** | 349 | 342 |
| Cash used in investing activities | **(196)** | (57) | (49) |
| Cash used in financing activities | **(71)** | (78) | (133) |
| Proportionate share of increase in cash and cash equivalents | **125** | 214 | 160 |

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Financial position | | |
| Current assets | **229** | 171 |
| Property, plant and equipment, net | **3,019** | 2,331 |
| Intangible assets | **210** | 166 |
| Goodwill | **959** | 321 |
| Deferred amounts and other assets | **267** | 270 |
| Current liabilities | **(239)** | (150) |
| Non-recourse long-term debt | **(951)** | (1,061) |
| Other long-term liabilities | **(47)** | (43) |
| Proportionate share of net assets | **3,447** | 2,005 |

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline) for $28 million (US$27 million), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

## 11. LONG-TERM INVESTMENTS

| December 31, | Ownership Interest | 2011 | 2010 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| **Equity investments** | | | |
| Sponsored Investments | | | |
| The Partnership | 23.0% | **1,711** | 1,473 |
| Enbridge Energy, Limited Partnership - Series AC | 66.7% | **453** | 463 |
| Corporate | | | |
| Noverco Common Shares | 38.9% | **-** | 14 |
| Other | 5.0%-20.0% | **35** | 13 |
| **Other investments** | | | |
| Corporate | | | |
| Noverco Preferred Shares | | **285** | 181 |
| Value Creation Inc. | | **29** | 29 |
| Fuel Cell Energy Ltd. | | **11** | 25 |
| Other | | **16** | - |
| | | **2,540** | 2,198 |

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $120 million at December 31, 2011 (2010 - $123 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

**The Partnership**

The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 23.0% ownership in EEP, through a 2.0% general partner interest, a 16.0% interest in Class A units, a 2.7% interest in Class B units and a 2.3% interest in EEP as a result of a 16.8% investment in EEM, which owns 13.3% of EEP through its 100% interest in EEP's i-units.

The Company recorded investment income inclusive of incentive earnings, before tax, of $296 million (2010 - $51 million; 2009 - $175 million) for the year ended December 31, 2011.

During the year ended December 31, 2011, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $66 million net of income taxes of $53 million and noncontrolling interests of $22 million, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 25.5% to 23.0%.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million before tax and noncontrolling interest, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 27.0% to 25.5%.

Although 83.2% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

**Enbridge Energy, Limited Partnership**

The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project (*Note 30*). The Company recorded investment income from EELP of $53 million for the year ended December 31, 2011 (2010 - $63 million; 2009 - $12 million).

During 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 - $40 million (US$39 million)) payable to the Company relating to its series AC interest in the Alberta Clipper project.

**Noverco**

During the year ended December 31, 2011, the Company invested $144 million in cash and $255 million in a dividend received from Noverco to increase its common share investment from 32.1% to 38.9%. In addition, the Company received $399 million of preferred shares which are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.40%. There has been no change in the accounting for the Company's common or preferred share investments in Noverco as a result of the restructuring. The Company's interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

The Company adjusted its preferred share investments in Noverco which are entitled to cumulative preferred dividends based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40% to $285 million at December 31, 2011 (2010 - $181 million) due to the restructure of Noverco in 2011.

The Company also reduced its equity investment in Noverco common shares to nil at December 31, 2011 (2010 - $14 million) due to the restructure. Noverco owns an approximate 8.9% (2010 - 9.0%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.5% (2010 - 2.9%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $187 million at December 31, 2011 (2010 - $154 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2011, the Company recorded equity investment loss of $6 million (2010 - $6 million of earnings; 2009 - $10 million of earnings) related to its interest in Noverco.

## 12. DEFERRED AMOUNTS AND OTHER ASSETS

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Regulatory assets | **1,434** | 1,419 |
| Long-term portion of derivative assets *(Note 23)* | **549** | 462 |
| Affiliate long-term note receivable *(Note 30)* | **336** | 334 |
| Pension asset *(Note 27)* | **320** | 301 |
| Contractual receivables | **288** | 277 |
| Other | **293** | 93 |
| | **3,220** | 2,886 |

At December 31, 2011, deferred amounts of $63 million (2010 - $66 million) were subject to amortization and are presented net of accumulated amortization of $43 million (2010 - $39 million). Amortization expense in 2011 was $6 million (2010 - $9 million; 2009 - $7 million).

## 13. INTANGIBLE ASSETS

| **December 31, 2011** | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | **13.4%** | **521** | **199** | **322** |
| Transportation agreements | **4.2%** | **241** | **79** | **162** |
| Power purchase agreements and other | **10.4%** | **122** | **6** | **116** |
| | | **884** | **284** | **600** |

| December 31, 2010 | Weighted Average Amortization Rate | Cost | Accumulated Amortization | Net |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Software | 13.4% | 457 | 172 | 285 |
| Transportation agreements | 4.2% | 231 | 66 | 165 |
| Power purchase agreements and other | 5.0% | 33 | 5 | 28 |
| | | 721 | 243 | 478 |

Total amortization expense for intangible assets was $61 million for the year ended December 31, 2011 (2010 - $60 million; 2009 - $44 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2012 through 2016 of $62 million, $55 million, $48 million, $43 million and $38 million, respectively.

## 14. GOODWILL

| | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing and Energy Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at December 31, 2009 | 19 | - | 45 | 308 | - | 372 |
| Foreign exchange and other | (1) | - | (3) | - | - | (4) |
| Business acquisition | 17 | - | - | - | - | 17 |
| Balance at December 31, 2010 | 35 | - | 42 | 308 | - | 385 |
| Foreign exchange and other | **-** | **-** | **1** | **-** | **-** | **1** |
| Acquired *(Note 6)* | **638** | **-** | **-** | **-** | **-** | **638** |
| Balance at December 31, 2011 | **673** | **-** | **43** | **308** | **-** | **1,024** |

In 2011, the Company recognized $638 million of goodwill on the acquisition of a 50% interest in Seaway Pipeline. In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns.

## 15. ACCOUNTS PAYABLE AND OTHER

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Operating accrued liabilities | **2,068** | 1,677 |
| Trade payables | **153** | 232 |
| Construction payables | **224** | 253 |
| Taxes payable | **283** | 156 |
| Current derivative liabilities *(Note 23)* | **711** | 138 |
| Security deposits | **84** | 78 |
| Contractor holdbacks | **40** | 78 |
| Other | **159** | 76 |
| | **3,722** | 2,688 |

# 16. DEBT

| December 31, | Weighted Average Interest Rate | Maturity | **2011** | 2010 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | | | | |
| Debentures | 8.20% | 2024 | **200** | 200 |
| Medium-term notes | 5.05% | 2012-2040 | **2,435** | 2,435 |
| Southern Lights project financing[1] | 2.52% | 2013-2014 | **1,449** | 1,488 |
| Commercial paper and credit facility draws, net | | | **26** | 26 |
| Other[2] | | | **13** | 15 |
| Gas Distribution | | | | |
| Debentures | 9.85% | 2024 | **85** | 235 |
| Medium-term notes | 5.51% | 2014-2050 | **2,295** | 2,195 |
| Commercial paper and credit facility draws, net | | | **556** | 334 |
| Sponsored Investments | | | | |
| Medium-term notes | 4.72% | 2014-2020 | **415** | 290 |
| Credit facility draws, net | | | **260** | 130 |
| Corporate | | | | |
| U.S. dollar term notes[3] | 5.48% | 2014-2017 | **1,119** | 1,094 |
| Medium-term notes | 4.74% | 2013-2040 | **3,518** | 2,918 |
| Commercial paper and credit facility draws, net[4] | | | **2,785** | 2,776 |
| Deferred debt issue costs and other | | | **(99)** | (95) |
| Total debt | | | **15,057** | 14,041 |
| Current maturities | | | **(252)** | (154) |
| Short-term borrowings | 1.07% | | **(548)** | (326) |
| Long-term debt | | | **14,257** | 13,561 |

*1 2011 - $360 million and US$1,071 million (2010 - $388 million and US$1,106 million).*
*2 Primarily capital lease obligations.*
*3 2011 - US$1,100 million (2010 - US$1,100 million).*
*4 2011 - $987 million and US$1,780 million (2010 - $2,515 million and US$265 million).*

Debenture and term note maturities for the years ending December 31, 2012 through 2016 are $252 million, $451 million, $898 million, $916 million and $701 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $557 million, $536 million, $515 million, $475 million and $450 million, respectively.

**INTEREST EXPENSE**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Debentures and medium-term notes | **598** | 578 | 494 |
| Non-recourse long-term debt *(Note 17)* | **65** | 75 | 83 |
| Commercial paper and credit facility draws | **71** | 63 | 71 |
| Southern Lights project financing | **38** | 37 | 45 |
| Capitalized | **(61)** | (66) | (96) |
| | **711** | 687 | 597 |

**CREDIT FACILITIES**

| **December 31, 2011** | Maturity Dates[2] | Total Facilities | Credit Facility Draws[3] | Available |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Liquids Pipelines | 2013 | **300** | **26** | **274** |
| Gas Distribution | 2012-2013 | **717** | **556** | **161** |
| Sponsored Investments | 2013 | **500** | **268** | **232** |
| Corporate | 2012-2016 | **5,653** | **2,832** | **2,821** |
| | | **7,170** | **3,682** | **3,488** |
| Southern Lights project financing[1] | 2013-2014 | **1,576** | **1,466** | **110** |
| Total credit facilities | | **8,746** | **5,148** | **3,598** |

*1 Total facilities inclusive of $61 million for debt service reserve letters of credit.*
*2 Total facilities include $30 million in demand facilities with no maturity date.*
*3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.17% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,079 million (2010 - $2,940 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

## 17. NON-RECOURSE DEBT

| December 31, | Weighted Average Interest Rate | Maturity | **2011** | 2010 |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Gas Pipelines, Processing and Energy Services | | | | |
| Long-term credit facilities[1] | | 2015 | **5** | 1 |
| Senior notes[2] | 6.78% | 2015-2025 | **325** | 347 |
| Term debt[3] | 3.54% | 2012-2019 | **31** | 29 |
| Capital lease obligations | 10.60% | 2020 | **31** | 32 |
| Sponsored Investments | | | | |
| Credit facilities | | 2012-2015 | **23** | 23 |
| Senior notes | 6.67% | 2015-2025 | **638** | 675 |
| Fair value increment on senior notes acquired | | | **25** | 29 |
| Deferred debt issue costs and other | | | **(5)** | (5) |
| Total non-recourse debt | | | **1,073** | 1,131 |
| Current maturities | | | **(122)** | (70) |
| Non-recourse long-term debt | | | **951** | 1,061 |

*1 2011 - US$5 million (2010 - US$1 million).*
*2 2011 - US$319 million (2010 - US$349 million).*
*3 2011 - US$26 million (2010 - US$24 million).*

Maturities on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $122 million, $78 million, $81 million, $86 million and $64 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $67 million, $62 million, $56 million, $51 million and $46 million, respectively.

Certain assets of Alliance Pipeline Canada and Alliance Pipeline US, with a carrying value of $959 million and $693 million, respectively, are pledged as collateral to Alliance Pipeline Canada and to Alliance Pipeline US lenders.

## 18. OTHER LONG-TERM LIABILITIES

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Future removal and site restoration reserves *(Note 5)* | **836** | 773 |
| Regulatory liabilities | **189** | 198 |
| Derivative liabilities *(Note 23)* | **433** | 133 |
| OPEB liabilities *(Note 27)* | **127** | 118 |
| Other | **307** | 251 |
| | **1,892** | 1,473 |

## 19. NONCONTROLLING INTERESTS

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Enbridge Energy Management, L.L.C. (EEM) | **475** | 394 |
| Enbridge Income Fund (the Fund) | **227** | 109 |
| Enbridge Gas Distribution Inc. (EGD) Preferred Shares | **100** | 100 |
| Talbot Windfarm, LP (Talbot) | **-** | 26 |
| Greenwich Windfarm, LP (Greenwich) | **26** | 12 |
| Other | **18** | 17 |
| | **846** | 658 |

Noncontrolling interests in EEM represents the 83.2% of the listed shares of EEM not held by the Company. During the year ended December 31, 2011, EEM completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests.

Noncontrolling interests in the Fund at December 31, 2011 represents 64.6% of interests that are held by third parties. During the year ended December 31, 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly owned subsidiary of Enbridge for proceeds of $1.2 billion. Ordinary trust units were issued by the Fund to partially finance the acquisition, resulting in an increase in interests held by third parties. Contributions from noncontrolling interests for the year ended December 31, 2011 included $168 million attributable to the Fund's common trust unit issuance.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2011, no preferred shares have been redeemed.

Noncontrolling interests in both Talbot and Greenwich represent 10% of partnership units held by a third party. During the year ended December 31, 2011, the Company acquired the remaining 10% interest in Talbot for $28 million, increasing its ownership interest to 100%. Effective October 21, 2011, ownership of Talbot was transferred to the Fund.

# 20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

**COMMON SHARES**

| | **2011** | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| December 31, | Number of Shares | Amount | Number of Shares | Amount | Number of Shares | Amount |
| *(millions of Canadian dollars; number of common shares in millions)* | | | | | | |
| Balance at beginning of year | **770** | **3,683** | 756 | 3,379 | 746 | 3,194 |
| Common shares issued | **-** | **-** | - | - | - | 4 |
| Shares issued on exercise of stock options | **4** | **57** | 6 | 80 | 2 | 38 |
| Dividend Reinvestment and Share Purchase Plan (DRIP) | **7** | **229** | 8 | 224 | 8 | 143 |
| Balance at end of year | **781** | **3,969** | 770 | 3,683 | 756 | 3,379 |

**PREFERENCE SHARES**

| | **2011** | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| December 31, | Number of Shares | Amount | Number of Shares | Amount | Number of Shares | Amount |
| *(millions of Canadian dollars; number of preference shares in millions)* | | | | | | |
| Preference shares, Series A | **5** | **125** | 5 | 125 | 5 | 125 |
| Preference shares, Series B issued[1] | **20** | **490** | - | - | - | - |
| Preference shares, Series D issued[2] | **18** | **441** | - | - | - | - |
| Balance at end of year | | **1,056** | | 125 | | 125 |

*1 Gross proceeds - $500 million; net issuance costs - $10 million.*
*2 Gross proceeds - $450 million; net issuance costs - $9 million.*

Characteristics of the preference shares are as follows:

| | Initial Yield | Dividend[1] | Per Share Cash Dividend Declared | Per share Base Redemption Value[2] | Redemption and Conversion Option Date [2,3] | Right to Convert[3,4] |
|---|---|---|---|---|---|---|
| *(Canadian dollars unless otherwise stated)* | | | | | | |
| Preference shares, Series A | 5.5% | 1.3750 | 1.3750 | 25 | - | - |
| Preference shares, Series B | 4.0% | 1.0000 | 0.4192 | 25 | June 1, 2017 | Series C |
| Preference shares, Series D | 4.0% | 1.0000 | 0.2705 | 25 | March1, 2018 | Series E |

*1 Fixed, cumulative, quarterly preferential dividend per share per year.*
*2 The Company may at its option, redeem all or a portion of the outstanding preference shares for the base redemption value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*
*3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified Series on the Conversion Option Date and every fifth anniversary thereafter.*
*4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C) or 2.37% (Series E)).*

Subsequent to year end, on January 18, 2012, the Company issued 20 million Series F Preference Shares for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to the same dividends, redemption and conversion terms as the Series B and Series D Preference Shares. Redemption of Series F Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series G can occur on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Series G Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the

quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.51%.

**EARNINGS PER COMMON SHARE**

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 25 million (2010 - 22 million; 2009 - 22 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

| December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(number of common shares in millions)* | | | |
| Weighted average shares outstanding | **751** | 741 | 728 |
| Effect of dilutive options | **10** | 7 | 5 |
| Diluted weighted average shares outstanding | **761** | 748 | 733 |

For the year ended December 31, 2011, 48,000 anti-dilutive stock options (2010 - 92,000; 2009 - 1,113,000) with a weighted average exercise price of $32.02 (2010 - $27.84; 2009 - $20.49) were excluded from the diluted earnings per share calculation.

**STOCK SPLIT**

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

**DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN**

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

**SHAREHOLDER RIGHTS PLAN**

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

## 21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 43 million have been issued to date. In 2007, a new reserve of 33 million common shares was approved and established and in 2011 an increase of 19 million to the reserved common shares was approved, resulting in a total of 52 million shares being available for the 2007 ISO and PBSO plans, of which 1 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

**INCENTIVE STOCK OPTIONS**

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2011 for ISOs is $16 million (2010 - $11 million; 2009 - $17 million).

### Outstanding Incentive Stock Options

| December 31, | **2011** | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| Options at beginning of year | **25,460** | **18.34** | 24,932 | 17.01 | 21,300 | 15.53 |
| Options granted | **6,041** | **28.78** | 4,000 | 22.70 | 6,056 | 19.81 |
| Options exercised | **(3,926)** | **14.23** | (3,436) | 14.52 | (2,374) | 11.01 |
| Options cancelled or expired | **(110)** | **25.87** | (36) | 12.45 | (50) | 20.33 |
| Options at end of year | **27,465** | **21.19** | 25,460 | 18.34 | 24,932 | 17.01 |
| Options vested | **14,214** | **17.93** | 13,764 | 16.01 | 13,100 | 14.48 |

The total intrinsic value of ISOs exercised during the year ended December 31, 2011 was $68 million (2010 - $38 million; 2009 - $22 million) and cash received on exercise was $56 million (2010 - $50 million; 2009 - $26 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2011 was $285 million (2010 - $182 million) and $194 million (2010 - $131 million), respectively.

### Incentive Stock Option Characteristics

| **December 31, 2011** | Options Outstanding | | | Options Vested | | |
|---|---|---|---|---|---|---|
| Exercise Price Range | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| 10.00-12.49 | **1,195** | **1.0** | **10.45** | **1,195** | **1.0** | **10.45** |
| 12.50-14.99 | **1,440** | **2.1** | **12.86** | **1,440** | **2.1** | **12.86** |
| 15.00-17.49 | **2,578** | **4.7** | **15.99** | **1,963** | **4.0** | **15.94** |
| 17.50-19.99 | **7,877** | **6.0** | **19.30** | **5,486** | **5.5** | **19.08** |
| 20.00-22.49 | **5,202** | **6.4** | **20.55** | **3,390** | **6.2** | **20.37** |
| 22.50-24.99 | **3,102** | **8.1** | **23.30** | **717** | **8.1** | **23.30** |
| 27.50-29.99 | **6,023** | **9.1** | **28.90** | **23** | **8.9** | **27.84** |
| 30.00-32.49 | **48** | **9.7** | **32.02** | **-** | **-** | **-** |
| | **27,465** | **6.5** | **21.08** | **14,214** | **4.9** | **17.83** |

The total fair value of options vested under the ISO Plan during the year ended December 31, 2011 was $17 million (2010 - $14 million; 2009 - $13 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| Fair value per option *(Canadian dollars)*[1] | **4.19** | 3.44 | 3.56 |
| Valuation assumptions | | | |
| Expected option term *(years)*[2] | **6** | 6 | 6 |
| Expected volatility[3] | **18.63%** | 19.72% | 28.08% |
| Expected dividend yield[4] | **3.40%** | 3.64% | 3.87% |
| Risk-free interest rate[5] | **2.85%** | 2.70% | 2.24% |

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair value per option were $4.01 (2010 - $3.28; 2009 - $3.37) for Canadian employees and US$5.11 (2010 - US$4.00; 2009 - US$3.43) for United States employees.*
2 *The expected option term is based on historical exercise practice.*
3 *Expected volatility is determined with reference to historic daily share price volatility. Beginning in 2010, implied volatility observable in call option values near the grant date is also considered in determining the expected volatility.*
4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and United States Treasury Bond Yields.*

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $24 million. The cost is expected to be fully recognized by December 31, 2014.

**PERFORMANCE BASED STOCK OPTIONS**

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2011 for PBSOs was $2 million (2010 - $2 million; 2009 - $2 million).

**Outstanding Performance Based Stock Options**

| December 31, | **2011** | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| Options at beginning of year | **4,294** | **18.51** | 6,790 | 16.85 | 7,476 | 16.36 |
| Options exercised | **(167)** | **18.29** | (2,078) | 13.12 | (686) | 11.58 |
| Options cancelled | **-** | **-** | (418) | 18.29 | - | - |
| Options at end of year | **4,127** | **18.52** | 4,294 | 18.51 | 6,790 | 16.85 |
| Options vested | **3,191** | **18.47** | 2,524 | 18.44 | 1,600 | 11.58 |

The total intrinsic value of PBSOs exercised during the year ended December 31, 2011 was $2 million (2010 - $26 million; 2009 - $6 million) and cash received on exercise was $3 million (2010 - $27 million; 2009 - $8 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2011 is $54 million (2010 - $30 million) and $42 million (2010 - $18 million), respectively.

**Performance Based Stock Option Characteristics**

| December 31, 2011 | Options Outstanding | | | Options Vested | | |
|---|---|---|---|---|---|---|
| Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price | Number | Weighted Average Remaining Life *(years)* | Weighted Average Exercise Price |
| *(options in thousands; exercise price in Canadian dollars)* | | | | | | |
| 18.29 | **3,627** | **3.6** | **18.29** | **2,891** | **3.6** | **18.29** |
| 20.21 | **500** | **3.6** | **20.21** | **300** | **3.6** | **20.21** |
| | **4,127** | **3.6** | **18.52** | **3,191** | **3.6** | **18.47** |

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2011 was $2 million (2010 - $2 million; 2009 - $2 million).

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $1 million. The cost is expected to be fully recognized by December 31, 2012.

**PERFORMANCE STOCK UNITS**

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2009, 2010 and 2011 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2011 for PSUs was $42 million (2010 - $27 million; 2009 - $20 million). To calculate the 2011 expense, multipliers of two, based upon multiplier estimates at December 31, 2011, were used for each of the 2009, 2010 and 2011 PSU grants.

**Outstanding Performance Stock Units**

| December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| Units at beginning of year | **955,894** | 660,832 | 590,856 |
| Units granted | **317,000** | 572,400 | 339,200 |
| Units matured | **(375,190)** | (319,634) | (303,764) |
| Dividend reinvestment | **39,453** | 42,296 | 34,540 |
| Units at end of year | **937,157** | 955,894 | 660,832 |

Of the PSUs outstanding at December 31, 2011, 610,459 units have a performance period ending December 31, 2012 and 326,698 have a performance period ending December 31, 2013. The total intrinsic value of PSUs outstanding at December 31, 2011 is $71 million (2010 - $54 million; 2009 - $31 million). The total amount paid during the year ended December 31, 2011 for PSUs was $17 million (2010 - $14 million; 2009 - $9 million).

**RESTRICTED STOCK UNITS**

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2011 for RSUs was $31 million (2010 - $29 million; 2009 - $23 million).

**Outstanding Restricted Stock Units**

| December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| Units at beginning of year | **2,095,970** | 1,975,754 | 1,400,068 |
| Units granted | **938,100** | 937,200 | 1,087,000 |
| Units cancelled | **(92,276)** | (60,908) | (36,858) |
| Units matured | **(1,132,674)** | (855,504) | (565,312) |
| Notional dividend reinvestment | **92,865** | 99,428 | 90,856 |
| Units at end of year | **1,901,985** | 2,095,970 | 1,975,754 |

The total intrinsic value of RSUs outstanding at December 31, 2011 is $72 million (2010 - $59 million; 2009 - $47 million). The total liability paid during the year ended December 31, 2011 for RSUs was $39 million (2010 - $24 million; 2009 - $12 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $68 million and is expected to be fully recognized by December 31, 2013.

## 22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

| | Net Investment Hedges | Cumulative Translation Adjustment | Equity Investees | Noncontrolling Interests | Cash Flow Hedges | Total |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Balance at January 1, 2009 | 278 | (275) | (8) | 17 | 21 | 33 |
| Changes during the year | 181 | (815) | (38) | 72 | 71 | (529) |
| Tax impact | (30) | - | 14 | - | (31) | (47) |
| | 151 | (815) | (24) | 72 | 40 | (576) |
| Balance at December 31, 2009 | 429 | (1,090) | (32) | 89 | 61 | (543) |
| Changes during the year | 61 | (274) | (18) | 33 | (133) | (331) |
| Tax impact | (10) | - | 7 | - | (5) | (8) |
| | 51 | (274) | (11) | 33 | (138) | (339) |
| Balance at December 31, 2010 | 480 | (1,364) | (43) | 122 | (77) | (882) |
| Changes during the year | **(21)** | **242**[1] | **(91)** | **13** | **(513)** | **(370)** |
| Tax impact | **2** | **-** | **30** | **-** | **126** | **158** |
| | **(19)** | **242** | **(61)** | **13** | **(387)** | **(212)** |
| Balance at December 31, 2011 | **461** | **(1,122)** | **(104)** | **135** | **(464)** | **(1,094)** |

*1 Changes in the Cumulative Translation Adjustment balance during the year included the release of a $155 million loss to earnings following the partial liquidation of an investment in a foreign subsidiary.*

## 23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

**MARKET PRICE RISK**

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within

business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances, if any, are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

**Foreign Exchange Risk**

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues and expenses denominated in United States dollars.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2011, would have resulted in a $310 million increase (2010 - $81 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

**Interest Rate Risk**

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.27%

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and a $457 million increase (2010 - $178 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011. A 1% increase across the interest rate yield curve, with all other variables constant, would have caused a $23 million decrease (2010 - $22 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

**Commodity Price Risk**

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and process business held by EEP.

The Company uses EaR as a metric to monitor certain commodity price risk exposures, principally those associated with its ownership of Aux Sable, its ownership of EEP and the activities of its energy services subsidiaries. The EaR metric measures the price exposures, net of the impact of financial derivatives used to manage such exposures. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from such commodity price risk over a one month period.

| | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Average EaR during the year | **23** | 22 |
| High EaR during the year | **27** | 29 |
| Low EaR during the year | **18** | 16 |
| Closing EaR at year end | **20** | 25 |

**Equity Price Risk**

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, RSUs (*Note 21*).

Due to revaluation of the equity derivative contracts at December 31, 2011, the impact of a $4 increase in the Company's share price would have been a $3 million increase in earnings (2010 - $2 million) and a $2 million increase in OCI (2010 - $1 million). The earnings impact of non-qualifying equity derivatives partially offsets earnings impacts due to the revaluation of liabilities associated with the Company's RSUs.

**TOTAL DERIVATIVE INSTRUMENTS**

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company had no outstanding fair value hedges as at December 31, 2011 or 2010.

| December 31, 2011 | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment Hedges | Non-Qualifying Derivative Instruments | Total Derivative Instruments |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Accounts receivable and other *(Note 7)* | | | | |
| Foreign exchange contracts | **4** | **15** | **315** | **334** |
| Interest rate contracts | **-** | **-** | **7** | **7** |
| Commodity contracts | **-** | **-** | **114** | **114** |
| Equity contracts | **3** | **-** | **7** | **10** |
| | **7** | **15** | **443** | **465** |
| Deferred amounts and other *(Note 12)* | | | | |
| Foreign exchange contracts | **15** | **79** | **203** | **297** |
| Interest rate contracts | **1** | **-** | **22** | **23** |
| Commodity contracts | **1** | **-** | **223** | **224** |
| Equity contracts | **3** | **-** | **2** | **5** |
| | **20** | **79** | **450** | **549** |
| Accounts payable and other *(Note 15)* | | | | |
| Foreign exchange contracts | **(4)** | **-** | **(275)** | **(279)** |
| Interest rate contracts | **(341)** | **-** | **(3)** | **(344)** |
| Commodity contracts | **(1)** | **-** | **(87)** | **(88)** |
| | **(346)** | **-** | **(365)** | **(711)** |
| Other long-term liabilities *(Note 18)* | | | | |
| Foreign exchange contracts | **(35)** | **(5)** | **(51)** | **(91)** |
| Interest rate contracts | **(303)** | **-** | **(18)** | **(321)** |
| Commodity contracts | **(2)** | **-** | **(19)** | **(21)** |
| | **(340)** | **(5)** | **(88)** | **(433)** |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | **(20)** | **89** | **192** | **261** |
| Interest rate contracts | **(643)** | **-** | **8** | **(635)** |
| Commodity contracts | **(2)** | **-** | **231** | **229** |
| Equity contracts | **6** | **-** | **9** | **15** |
| | **(659)** | **89** | **440** | **(130)** |

| December 31, 2010 | Derivative Instruments Used as Cash Flow Hedges | Derivative Instruments Used as Net Investment Hedges | Non-Qualifying Derivative Instruments | Total Derivative Instruments |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Accounts receivable and other *(Note 7)* | | | | |
| Foreign exchange contracts | 4 | 15 | 111 | 130 |
| Interest rate contracts | 6 | - | - | 6 |
| Commodity contracts | - | - | 33 | 33 |
| Equity contracts | - | - | 1 | 1 |
| | 10 | 15 | 145 | 170 |
| Deferred amounts and other *(Note 12)* | | | | |
| Foreign exchange contracts | 18 | 100 | 275 | 393 |
| Interest rate contracts | 67 | - | - | 67 |
| Commodity contracts | - | - | 2 | 2 |
| | 85 | 100 | 277 | 462 |
| Accounts payable and other *(Note 15)* | | | | |
| Foreign exchange contracts | (4) | - | (11) | (15) |
| Interest rate contracts | (72) | - | - | (72) |
| Commodity contracts | - | - | (51) | (51) |
| | (76) | - | (62) | (138) |
| Other long-term liabilities *(Note 18)* | | | | |
| Foreign exchange contracts | (47) | - | (3) | (50) |
| Interest rate contracts | (80) | - | - | (80) |
| Commodity contracts | - | - | (3) | (3) |
| | (127) | - | (6) | (133) |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | (29) | 115 | 372 | 458 |
| Interest rate contracts | (79) | - | - | (79) |
| Commodity contracts | - | - | (19) | (19) |
| Equity contracts | - | - | 1 | 1 |
| | (108) | 115 | 354 | 361 |

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

| | **2011** | | 2010 | |
|---|---|---|---|---|
| December 31, | Maturity | Notional Principal or Quantity Outstanding | Maturity | Notional Principal or Quantity Outstanding |
| U.S. dollar forwards - purchase *(millions of United States dollars)* | **2012-2020** | **1,281** | 2011-2020 | 1,185 |
| U.S. dollar forwards - sell *(millions of United States dollars)* | **2012-2020** | **10,866** | 2011-2020 | 3,516 |
| Interest rate contracts *(millions of Canadian dollars)* | **2012-2029** | **16,540** | 2011-2029 | 10,772 |
| Commodity contracts - energy *(billions of cubic feet equivalent)* | **2012-2013** | **2** | 2011-2013 | 41 |
| Commodity contracts - power *(megawatts per hour)* | **2012-2024** | **53** | 2011-2024 | 2 |
| Equity contracts *(millions of shares)* | **2011-2013** | **2** | 2011-2012 | 1 |

**The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income**
The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

| Year ended December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Amount of unrealized gain/(loss) recognized in OCI | | |
| Cash flow hedges | | |
| Foreign exchange contracts | **(22)** | (25) |
| Interest rate contracts | **(545)** | (172) |
| Commodity contracts | **(6)** | 97 |
| Equity contracts | **6** | (1) |
| Net investment hedges | | |
| Foreign exchange contracts | **(26)** | 19 |
| Total unrealized loss recognized in OCI | **(593)** | (82) |
| Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)* | | |
| Cash flow hedges | | |
| Foreign exchange contracts[1] | **1** | (7) |
| Interest rate contracts[2] | **18** | 68 |
| Commodity contracts[3] | **5** | (95) |
| Equity contracts[4] | **(2)** | 1 |
| Total gain/(loss) reclassified from AOCI to earnings *(effective portion)* | **22** | (33) |
| Amount of ineffectiveness reclassified from AOCI to earnings | | |
| Cash flow hedges | | |
| Interest rate contracts[2] | **11** | - |
| Total ineffectiveness reclassified from AOCI to earnings | **11** | - |

*1 (Gain)/loss reported within Other income in the Consolidated Statements of Earnings.*
*2 (Gain)/loss reported within Interest expense in the Consolidated Statements of Earnings.*
*3 (Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
*4 (Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $33 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2011.

**Non-Qualifying Derivatives**
The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Foreign exchange contracts[1] | **(179)** | 33 | 232 |
| Interest rate contracts[2] | **9** | (2) | 2 |
| Commodity contracts[3] | **244** | (5) | (88) |
| Equity contracts[4] | **4** | - | - |
| Total unrealized derivative fair value gain | **78** | 26 | 146 |

*1 Gain/(loss) reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
*2 Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.*
*3 Gain/(loss) reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
*4 Gain reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

Additional information regarding the Company's derivative instruments is included in Note 24, *Fair Value of Financial Instruments.*

**LIQUIDITY RISK**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

**Maturities of Financial Instruments**

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17).*

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

| | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Cash inflows | 440 | 213 | 180 | 69 | 74 | 105 |
| Cash outflows | (401) | (133) | (124) | (77) | (65) | (610) |
| Net cash flows | 39 | 80 | 56 | (8) | 9 | (505) |

**CREDIT RISK**

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and industry standard netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011 and 2010, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments.

| December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Canadian financial institutions | **426** | 451 |
| Non-Canadian financial institutions | **509** | 125 |
| Other | **73** | 50 |
| | **1,008** | 626 |

Credit risk also arises from trade and other long-term receivables and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, *Fair Value of Financial Instruments*.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

| Year ended December 31, | 2011 | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Balance at beginning of year | **(62)** | (74) |
| Additional allowance | **(26)** | (23) |
| Amounts used | **32** | 35 |
| Balance at end of year | **(56)** | (62) |

## 24. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

| **December 31, 2011** | Held for Trading | Available for Sale[1] | Loans and Receivables | Held to Maturity | Other Financial Liabilities | Qualifying Derivatives | Non-Financial Instruments | Total | Fair Value[2] |
|---|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | | |
| **Assets** | | | | | | | | | |
| Cash and cash equivalents | **420** | **-** | **-** | **-** | **-** | **-** | **-** | **420** | **420** |
| Accounts receivable and other | **443** | **-** | **2,392** | **-** | **-** | **22** | **279** | **3,136** | **2,857** |
| Long-term investments | **-** | **56** | **-** | **285** | **-** | **-** | **2,199** | **2,540** | **285** |
| Deferred amounts and other assets | **450** | **-** | **4** | **-** | **-** | **99** | **2,667** | **3,220** | **553** |
| **Liabilities** | | | | | | | | | |
| Bank indebtedness | **102** | **-** | **-** | **-** | **-** | **-** | **-** | **102** | **102** |
| Short-term borrowings | **-** | **-** | **-** | **-** | **548** | **-** | **-** | **548** | **548** |
| Accounts payable and other | **365** | **-** | **-** | **-** | **2,728** | **346** | **283** | **3,722** | **3,439** |
| Interest payable | **-** | **-** | **-** | **-** | **114** | **-** | **-** | **114** | **114** |
| Long-term debt | **-** | **-** | **-** | **-** | **14,509** | **-** | **-** | **14,509** | **16,772** |
| Non-recourse long-term debt | **-** | **-** | **-** | **-** | **1,073** | **-** | **-** | **1,073** | **1,248** |
| Other long-term liabilities | **88** | **-** | **-** | **-** | **-** | **345** | **1,459** | **1,892** | **433** |

| December 31, 2010 | Held for Trading | Available for Sale[1] | Loans and Receivables | Held to Maturity | Other Financial Liabilities | Qualifying Derivatives | Non-Financial Instruments | Total | Fair Value[2] |
|---|---|---|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | | | | |
| **Assets** | | | | | | | | | |
| Cash and cash equivalents | 342 | - | - | - | - | - | - | 342 | 342 |
| Accounts receivable and other | 145 | - | 2,113 | - | - | 25 | 423 | 2,706 | 2,283 |
| Long-term investments | - | 54 | 339 | 181 | - | - | 1,624 | 2,198 | 520 |
| Deferred amounts and other assets | 277 | - | 334 | - | - | 185 | 2,090 | 2,886 | 462 |
| **Liabilities** | | | | | | | | | |
| Bank indebtedness | 100 | - | - | - | - | - | - | 100 | 100 |
| Short-term borrowings | - | - | - | - | 326 | - | - | 326 | 326 |
| Accounts payable and other | 62 | - | - | - | 2,393 | 76 | 157 | 2,688 | 2,531 |
| Interest payable | - | - | - | - | 117 | - | - | 117 | 117 |
| Long-term debt | - | - | - | - | 13,715 | - | - | 13,715 | 14,770 |
| Non-recourse long-term debt | - | - | - | - | 1,131 | - | - | 1,131 | 1,298 |
| Other long-term liabilities | 6 | - | - | - | - | 127 | 1,340 | 1,473 | 133 |

*1 Classified as Other investments carried at cost under U.S. GAAP.*

*2 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

**FAIR VALUE OF DERIVATIVES**

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

**Level 1**

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment.

**Level 2**

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as

well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services and Corporate segments.

**Level 3**

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

| **December 31, 2011** | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | **-** | **334** | **-** | **334** |
| Interest rate contracts | **-** | **7** | **-** | **7** |
| Commodity contracts | **1** | **59** | **54** | **114** |
| Equity contracts | **-** | **10** | **-** | **10** |
| | **1** | **410** | **54** | **465** |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | **-** | **297** | **-** | **297** |
| Interest rate contracts | **-** | **23** | **-** | **23** |
| Commodity contracts | **-** | **193** | **31** | **224** |
| Equity contracts | **-** | **5** | **-** | **5** |
| | **-** | **518** | **31** | **549** |
| Financial liabilities | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | **-** | **(279)** | **-** | **(279)** |
| Interest rate contracts | **-** | **(344)** | **-** | **(344)** |
| Commodity contracts | **-** | **(42)** | **(46)** | **(88)** |
| | **-** | **(665)** | **(46)** | **(711)** |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | **-** | **(91)** | **-** | **(91)** |
| Interest rate contracts | **-** | **(321)** | **-** | **(321)** |
| Commodity contracts | **-** | **(16)** | **(5)** | **(21)** |
| | **-** | **(428)** | **(5)** | **(433)** |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | **-** | **261** | **-** | **261** |
| Interest rate contracts | **-** | **(635)** | **-** | **(635)** |
| Commodity contracts | **1** | **194** | **34** | **229** |
| Equity contracts | **-** | **15** | **-** | **15** |
| | **1** | **(165)** | **34** | **(130)** |

| December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | |
| Financial assets | | | | |
| Current derivative assets | | | | |
| Foreign exchange contracts | - | 130 | - | 130 |
| Interest rate contracts | - | 6 | - | 6 |
| Commodity contracts | - | 5 | 28 | 33 |
| Other contracts | - | - | 1 | 1 |
| | - | 141 | 29 | 170 |
| Long-term derivative assets | | | | |
| Foreign exchange contracts | - | 393 | - | 393 |
| Interest rate contracts | - | 67 | - | 67 |
| Commodity contracts | - | - | 2 | 2 |
| | - | 460 | 2 | 462 |
| Financial liabilities | | | | |
| Current derivative liabilities | | | | |
| Foreign exchange contracts | - | (15) | - | (15) |
| Interest rate contracts | - | (72) | - | (72) |
| Commodity contracts | (9) | (2) | (40) | (51) |
| | (9) | (89) | (40) | (138) |
| Long-term derivative liabilities | | | | |
| Foreign exchange contracts | - | (50) | - | (50) |
| Interest rate contracts | - | (80) | - | (80) |
| Commodity contracts | - | (1) | (2) | (3) |
| | - | (131) | (2) | (133) |
| Total net derivative asset/(liability) | | | | |
| Foreign exchange contracts | - | 458 | - | 458 |
| Interest rate contracts | - | (79) | - | (79) |
| Commodity contracts | (9) | 2 | (12) | (19) |
| Other contracts | - | - | 1 | 1 |
| | (9) | 381 | (11) | 361 |

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

| Year ended December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Level 3 net derivative liability at beginning of year | **(11)** | (28) |
| Total gains/(losses), unrealized | | |
| Included in earnings[1] | **46** | 19 |
| Included in OCI | **(4)** | 3 |
| Settlements | **3** | (5) |
| Level 3 net derivative asset/(liability) at end of year | **34** | (11) |

*1 Gain reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense.*

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2011 and December 31, 2010.

## 25. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and noncontrolling interests less cash and cash equivalents (excluding restricted cash of amounts in trust and proportionately consolidated cash from joint ventures, net of bank indebtedness). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows.

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Short-term borrowings | **548** | 326 |
| Long-term debt (includes current portion) | **14,608** | 13,810 |
| Noncontrolling interests | **846** | 658 |
| Shareholders' equity | **10,122** | 8,601 |
| Cash and cash equivalents | **(77)** | (282) |
| | **26,047** | 23,113 |

The Company seeks to balance a number of objectives when managing capital, including enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; ensuring liquidity for growth opportunities; and minimizing cost of capital. These objectives are primarily met through maintenance of an investment grade credit rating, disciplined investment criteria and sufficient committed credit facilities. Capital is available generally through the issuance of both short and long-term debt and various forms of equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse short and long-term debt, was 58.0% compared with 60.4% at the end of 2010.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. This covenant also applies to the Company's credit facilities that are used to backstop its commercial paper program. Total consolidated capitalization consists of shareholders' equity, long-term debt, noncontrolling interests and future income taxes.

During the year ended December 31, 2011, the Company was in compliance with externally imposed capital requirements.

## 26. INCOME TAXES

**INCOME TAX RATE RECONCILIATION**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings attributable to Enbridge Inc. before income taxes | **1,572** | 1,221 | 1,868 |
| Combined statutory income tax rate | **27.3%** | 28.9% | 30.5% |
| Income taxes at statutory rate | **429** | 353 | 570 |
| Increase/(decrease) resulting from: | | | |
| Future income taxes related to regulated operations | **(35)** | (62) | (68) |
| Higher/(lower) foreign tax rates | **84** | (22) | (61) |
| Tax rates and legislated tax changes | **2** | (23) | (58) |
| Non-taxable items, net | **1** | (2) | 11 |
| Intercompany sale of investments[1] | **98** | - | (99) |
| Other | **(11)** | 7 | 11 |
| Income taxes | **568** | 251 | 306 |
| Effective income tax rate | **36.1%** | 20.6% | 16.4% |

*1 In October 2011, EPI sold three renewable energy assets to the Fund. As the transaction occurred between entities under common control of the Company, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $98 million remain as a charge to earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.*

**COMPONENTS OF FUTURE INCOME TAXES**

| December 31, | **2011** | 2010 |
|---|---|---|
| *(millions of Canadian dollars)* | | |
| Net future income tax liabilities/(assets) | | |
| Differences in accounting and tax bases of property, plant and equipment | **1,831** | 1,468 |
| Differences in accounting and tax bases of investments | **603** | 479 |
| Regulatory assets/(liabilities) | **308** | 340 |
| Financial instruments | **(24)** | 105 |
| Loss carryforwards | **(126)** | (81) |
| Other | **63** | 56 |
| Net future income tax liability | **2,655** | 2,367 |

Net future income tax liability of $2,655 million (2010 - $2,367 million) is comprised of future income tax liabilities of $2,696 million (2010 - $2,447 million) net of future income tax assets of $41 million (2010 - $80 million).

At December 31, 2011, the Company had recognized the benefit of unused tax loss carryforwards of $401 million (2010 - $248 million) which start to expire in 2020 and beyond.

**GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings before income taxes | | | |
| Canada | **600** | 711 | 954 |
| United States | **839** | 379 | 334 |
| Other | **133** | 131 | 580 |
| | **1,572** | 1,221 | 1,868 |
| Current income taxes | | | |
| Canada | **207** | (29) | 49 |
| United States | **(48)** | 37 | 35 |
| Other | **(6)** | 5 | 4 |
| | **153** | 13 | 88 |
| Future income taxes | | | |
| Canada | **31** | 134 | 117 |
| United States | **384** | 104 | 101 |
| | **415** | 238 | 218 |
| Current and future income taxes | **568** | 251 | 306 |

## 27. POST-EMPLOYMENT BENEFITS

**PENSION PLANS**

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

**Defined Benefit Plans**

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

| | Effective Date of Most Recently Filed Actuarial Valuation | Effective Date of Next Required Actuarial Valuation |
|---|---|---|
| Canadian Plans | | |
| Liquids Pipelines | December 31, 2010 | December 31, 2011 |
| Gas Distribution | December 31, 2009 | December 31, 2012 |
| United States Plan | December 31, 2010 | December 31, 2011 |

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

**Defined Contribution Plans**

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

**Post-Employment Benefits Other than Pensions**

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

**DEFINED BENEFIT PLANS**

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| December 31, | **2011** | 2010 | **2011** | 2010 |
| *(millions of Canadian dollars)* | | | | |
| **Change in accrued benefit obligation** | | | | |
| Benefit obligation at beginning of year | **1,323** | 1,119 | **195** | 170 |
| Service cost | **61** | 48 | **6** | 5 |
| Interest cost | **73** | 72 | **11** | 11 |
| Amendments | **-** | - | **-** | 6 |
| Employees' contributions | **-** | - | **1** | 1 |
| Actuarial loss[1] | **270** | 145 | **28** | 12 |
| Benefits paid | **(54)** | (52) | **(7)** | (7) |
| Other | **8** | - | **7** | - |
| Effect of foreign exchange rate changes | **5** | (9) | **2** | (3) |
| Benefit obligation at end of year | **1,686** | 1,323 | **243** | 195 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | **1,324** | 1,167 | **41** | 38 |
| Actual return on plan assets[1] | **16** | 127 | **1** | 2 |
| Employer's contributions | **72** | 89 | **13** | 9 |
| Employees' contributions | **-** | - | **1** | 1 |
| Benefits paid | **(54)** | (52) | **(7)** | (7) |
| Other | **4** | (1) | **4** | - |
| Effect of foreign exchange rate changes | **3** | (6) | **1** | (2) |
| Fair value of plan assets at end of year | **1,365** | 1,324 | **54** | 41 |
| **Funded status** | | | | |
| Benefit obligation | **(1,686)** | (1,323) | **(243)** | (195) |
| Fair value of plan assets | **1,365** | 1,324 | **54** | 41 |
| Overfunded/(underfunded) status at end of year | **(321)** | 1 | **(189)** | (154) |
| Unamortized prior service cost | **2** | 4 | **5** | 6 |
| Unamortized transitional obligation/(asset) | **(9)** | (11) | **7** | 8 |
| Unamortized net loss | **648** | 307 | **50** | 22 |
| Net amount recognized in the Consolidated Statements of Financial Position at end of year | **320** | 301 | **(127)** | (118) |
| Presented as follows: | | | | |
| Deferred amounts and other assets *(Note 12)* | **320** | 301 | **-** | - |
| Other long-term liabilities *(Note 18)* | **-** | - | **(127)** | (118) |

*1 Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2011** | 2010 | 2009 | **2011** | 2010 | 2009 |
| Discount rate | **4.46%** | 5.64% | 6.46% | **4.44%** | 5.55% | 6.28% |
| Average rate of salary increases | **3.50%** | 3.50% | 3.73% | | | |

**Net Benefit Costs Recognized**

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2011** | 2010 | 2009 | **2011** | 2010 | 2009 |
| *(millions of Canadian dollars)* | | | | | | |
| Benefits earned during the year | **61** | 48 | 53 | **6** | 5 | 4 |
| Interest cost on projected benefit obligations | **73** | 72 | 71 | **11** | 11 | 11 |
| Actual return on plan assets | **(16)** | (127) | (51) | **(1)** | (2) | (6) |
| Difference between actual and expected return on plan assets | **(76)** | 47 | (27) | **(2)** | - | 3 |
| Amortization of prior service costs | **2** | 2 | 2 | **1** | - | - |
| Amortization of transitional obligation | **(2)** | (2) | (2) | **1** | 1 | 1 |
| Amortization of actuarial loss | **25** | 19 | 21 | **1** | 1 | 1 |
| Amount charged to EEP[1] | **(15)** | (15) | (20) | **(6)** | (5) | (5) |
| Net defined benefit costs on an accrual basis | **52** | 44 | 47 | **11** | 11 | 9 |
| Defined contribution benefit costs | **4** | 5 | 4 | **-** | - | - |
| Net benefit cost recognized in the Consolidated Statements of Earnings | **56** | 49 | 51 | **11** | 11 | 9 |

*1 EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.*

For certain gas distribution businesses, regulatory adjustments are recorded in the Consolidated Statement of Earnings and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Differences arise since accounting is based on an accrual basis whereas ratemaking is based on a cash basis or funding approach. Regulatory assets or liabilities recognized in the Consolidated Statements of Financial Position are disclosed in Note 5.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows.

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| Year ended December 31, | **2011** | 2010 | 2009 | **2011** | 2010 | 2009 |
| Discount rate | **5.64%** | 6.47% | 6.59% | **5.55%** | 6.31% | 6.42% |
| Average rate of return on pension plan assets | **7.30%** | 7.30% | 7.30% | **6.00%** | 6.00% | 6.09% |
| Average rate of salary increases | **3.50%** | 3.73% | 5.00% | | | |

**MEDICAL COST TRENDS**

The assumed rates for the next year used to measure the expected cost of benefits are as follows.

| | Medical Cost Trend Rate Assumption for Next Fiscal Year | Ultimate Medical Cost Trend Rate Assumption | Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved |
|---|---|---|---|
| Canadian Plans | | | |
| Drugs | 8.4% | 4.5% | 2029 |
| Other Medical and Dental | 4.5% | 4.5% | 2029 |
| United States Plan | 7.8% | 4.5% | 2030 |

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $36 million in the accumulated post-employment benefit obligations and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $29 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

**PLAN ASSETS**

The Company manages the investment risk of its defined benefit pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

**Target Mix for Plan Assets**

| | Liquids Pipelines Pension Plan | Gas Distribution Pension Plan | United States Plan |
|---|---|---|---|
| Equity securities | 62.5% | 53.5% | 62.5% |
| Fixed income securities | 30.0% | 40.0% | 30.0% |
| Other | 7.5% | 6.5% | 7.5% |

**Expected Rate of Return on Plan Assets**

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | **2011** | 2010 | **2011** | 2010 |
| Canadian Plans | 7.0% | 7.25% | | |
| United States Plan | 7.5% | 7.75% | 6.0% | 6.00% |

**Major Categories of Plan Assets**

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2011, assets securing pension benefits were invested 56.6% (2010 - 60.2%) in equity securities, 36.5% (2010 - 33.8%) in fixed income securities and 6.9% (2010 - 6.0%) in other. OPEB assets securing OPEB benefits were invested 55.3% (2010 - 51.2%) in equity securities, 40.3% (2010 - 48.8%) in fixed income securities and 4.3% (2010 - nil) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $82 million (2010 - $69 million) have been excluded from the table below.

| December 31, | **2011** | | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1[1] | Level 2[2] | Level 3[3] | Total | Level 1[1] | Level 2[2] | Level 3[3] | Total |
| *(millions of Canadian dollars)* | | | | | | | | |
| **Pension benefits** | | | | | | | | |
| Cash and cash equivalents | **14** | **-** | **-** | **14** | 10 | - | - | 10 |
| Fixed income securities | | | | | | | | |
| Canadian government bonds | **-** | **115** | **-** | **115** | - | 97 | - | 97 |
| Corporate bonds and debentures | **-** | **4** | **-** | **4** | 4 | - | - | 4 |
| Canadian corporate bond index fund | **158** | **-** | **-** | **158** | 151 | - | - | 151 |
| Canadian government bond index fund | **157** | **-** | **-** | **157** | 149 | - | - | 149 |
| United States debt index fund | **62** | **-** | **-** | **62** | 47 | - | - | 47 |
| Equity | | | | | | | | |
| Canadian equity securities | **148** | **-** | **-** | **148** | 163 | - | - | 163 |
| Canadian equity funds | **23** | **74** | **-** | **97** | 26 | 80 | - | 106 |
| United States equity funds | **172** | **89** | **-** | **261** | 147 | 76 | - | 223 |
| Global equity funds | **192** | **7** | **-** | **199** | 221 | 19 | - | 240 |
| Private equity investment[4] | **-** | **-** | **68** | **68** | - | - | 65 | 65 |
| **OPEB** | | | | | | | | |
| Cash and cash equivalents | **3** | **-** | **-** | **3** | - | - | - | - |
| Fixed income securities | | | | | | | | |
| United States government and government agency bonds | **22** | **-** | **-** | **22** | 20 | - | - | 20 |
| Equity | | | | | | | | |
| United States equity funds | **15** | **14** | **-** | **29** | 9 | - | - | 9 |
| Global equity funds | **-** | **-** | **-** | **-** | - | 12 | - | 12 |

*1 Level 1 assets include assets with quoted prices in active markets for identical assets.*
*2 Level 2 assets include assets with significant observable inputs.*
*3 Level 3 assets include assets with significant unobservable inputs.*
*4 The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.*

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows.

| | Private Equity Investment |
|---|---|
| Balance at beginning of year | 65 |
| Total gains, unrealized | 8 |
| Purchases, issuances, settlements, net | (5) |
| Balance at end of year | 68 |

**PLAN CONTRIBUTIONS BY THE COMPANY**

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Year ended December 31, | **2011** | 2010 | **2011** | 2010 |
| *(millions of Canadian dollars)* | | | | |
| Total contributions | **72** | 89 | **13** | 9 |
| Contributions expected to be paid in 2012 | **94** | | **11** | |

**BENEFITS EXPECTED TO BE PAID BY THE COMPANY**

| Year ended December 31, | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-2021 |
|---|---|---|---|---|---|---|
| *(millions of Canadian dollars)* | | | | | | |
| Expected future benefit payments | 66 | 68 | 72 | 76 | 80 | 466 |

## 28. OTHER INCOME

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Net foreign currency gains/(loss) | **(109)** | 132 | 444 |
| Gain on reduction of EEP ownership interest | **141** | 81 | - |
| AEDC | **3** | 80 | 135 |
| Interest income on affiliate loans | **38** | 37 | 38 |
| Noverco preferred dividends income | **30** | 15 | 15 |
| Hurricane insurance recoveries | **-** | 5 | 13 |
| OCENSA investment income | **-** | - | 6 |
| Other | **9** | 24 | 27 |
| | **112** | 374 | 678 |

## 29. CHANGES IN OPERATING ASSETS AND LIABILITIES

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Accounts receivable and other | **(94)** | (480) | 99 |
| Inventory | **54** | (42) | 99 |
| Deferred amounts and other assets | **(253)** | (98) | (354) |
| Accounts payable and other | **504** | 254 | 105 |
| Interest payable | **(3)** | 13 | 2 |
| Other long-term liabilities | **43** | 60 | 281 |
| | **251** | (293) | 232 |

## 30. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows.

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| EEP | **380** | 332 | 342 |
| Vector Pipeline | **6** | 7 | 6 |
| | **386** | 339 | 348 |

At December 31, 2011, the Company had accounts receivable of $35 million (2010 - $29 million) from EEP and nil (2010 - nil) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principal amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Alliance Pipeline Canada | **25** | 25 | 24 |
| Alliance Pipeline US | **17** | 17 | 18 |
| Vector Pipeline | **25** | 28 | 29 |
| | **67** | 70 | 71 |

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Purchases | **1** | 2 | 16 |
| Sales | **-** | - | (6) |
| | **1** | 2 | 10 |

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Alliance Pipeline Canada | **17** | 13 | 9 |
| Alliance Pipeline US | **11** | 9 | 7 |
| Vector Pipeline | **11** | 10 | 16 |
| | **39** | 32 | 32 |

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Purchases | **122** | 151 | 80 |
| Sales | **(4)** | (3) | (7) |
| | **118** | 148 | 73 |

**ALBERTA CLIPPER PROJECT**

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2011, the Company had met all funding commitments. The Company funded 66.7% of the project's equity requirements through EELP, an equity investee.

The Company also provided a $348 million (US$342 million) (2010 - $346 million (US$347 million)) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 - $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 - $12

million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year ended December 31, 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 - $40 million (US$39 million)) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

**SPEARHEAD NORTH PIPELINE**
In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

**SOUTHERN LIGHTS PIPELINE**
In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 - $21 million) to the Company to lease Line 13.

**LONG-TERM RECEIVABLE FROM AFFILIATE**
An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

**LAKEHEAD LINE 6B CRUDE OIL RELEASE**
In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million (2010 - $18 million) for the year ended December 31, 2011.

## 31. COMMITMENTS AND CONTINGENCIES

**COMMITMENTS**
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation totaling $4,120 million which are expected to be paid within the next five years.

**ENBRIDGE GAS DISTRIBUTION INC.**
**Bloor Street Incident**
EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

**ENBRIDGE GAS NEW BRUNSWICK INC.**
**Regulatory Matters**
On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and

influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 - $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

**ENBRIDGE ENERGY PARTNERS, L.P.**
**EEP Lakehead System Line 6A and 6B Crude Oil Releases**

Enbridge holds an approximate 23.0% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas – a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the EPA directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to

incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

### Line 6A Crude Oil Release

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

### Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

### Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B

crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

**TAX MATTERS**

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

**OTHER LEGAL AND REGULATORY PROCEEDINGS**

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

## 32. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

## 33. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

**EARNINGS**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | | | |
| Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP | **991** | 963 | 1,555 |
| Earnings attributable to Enbridge Inc. under Canadian GAAP | **1,004** | 970 | 1,562 |
| Dilution gains, net of tax[4] | **(88)** | (52) | - |
| Gain on acquisition, net of tax[1] | **-** | 20 | - |
| Inventory valuation adjustment, net of tax[2] | **13** | 4 | (24) |
| Amortization of underfunded pension adjustment[3] | **(7)** | (7) | (7) |
| Unrealized foreign exchange loss adjustment[12] | **155** | - | - |
| Earnings/(loss) attributable to noncontrolling interests | | | |
| EEP | **351** | (172) | 177 |
| Other | **56** | 25 | 37 |
| Earnings under U.S. GAAP | **1,484** | 788 | 1,745 |
| (Earnings)/loss attributable to noncontrolling interests | **(407)** | 147 | (214) |
| Earnings attributable to Enbridge Inc. under U.S. GAAP | **1,077** | 935 | 1,531 |
| Preference share dividends | **(13)** | (7) | (7) |
| Earnings attributable to Enbridge Inc. common shareholders under U.S. GAAP | **1,064** | 928 | 1,524 |
| Earnings per common share attributable to Enbridge Inc. common shareholders | **1.42** | 1.25 | 2.09 |
| Diluted earnings per common share attributable to Enbridge Inc. common shareholders | **1.40** | 1.24 | 2.08 |

**COMPREHENSIVE INCOME**

| Year ended December 31, | **2011** | 2010 | 2009 |
|---|---|---|---|
| *(millions of Canadian dollars)* | | | |
| Earnings under U.S. GAAP | **1,484** | 788 | 1,745 |
| Other comprehensive loss including noncontrolling interests under Canadian GAAP | **(225)** | (372) | (648) |
| Underfunded pension adjustment[3] | **(145)** | (38) | 11 |
| Unrealized foreign exchange loss adjustment[12] | **(155)** | - | - |
| Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP[4] | **(124)** | (29) | (62) |
| Other comprehensive loss including noncontrolling interests under U.S. GAAP | **(649)** | (439) | (699) |
| Comprehensive income | **835** | 349 | 1,046 |
| Comprehensive (income)/loss attributable to noncontrolling interests | **(270)** | 224 | (80) |
| Comprehensive income attributable to Enbridge Inc. under U.S. GAAP | **565** | 573 | 966 |
| Preference share dividends | **(13)** | (7) | (7) |
| Comprehensive income attributable to Enbridge Inc. common shareholders under U.S. GAAP | **552** | 566 | 959 |

**FINANCIAL POSITION**

| December 31, | **2011** | | 2010 | |
|---|---|---|---|---|
| | **Canada** | **United States** | Canada | United States |
| *(millions of Canadian dollars)* | | | | |
| **Assets** | | | | |
| Current assets | | | | |
| Cash and cash equivalents[4,6] | **420** | **811** | 342 | 456 |
| Accounts receivable and other[4,6,9] | **3,136** | **3,990** | 2,706 | 3,582 |
| Inventory[2,4,6] | **739** | **714** | 813 | 915 |
| | **4,295** | **5,515** | 3,861 | 4,953 |
| Property, plant and equipment, net[4,6,8,9] | **22,623** | **31,833** | 20,332 | 28,562 |
| Long-term investments[4,6] | **2,540** | **510** | 2,198 | 367 |
| Deferred amounts and other assets[3,4,6,7,9] | **3,220** | **2,615** | 2,886 | 2,212 |
| Intangible assets[4,8] | **600** | **798** | 478 | 676 |
| Goodwill[4,8] | **1,024** | **1,091** | 385 | 445 |
| Future income taxes[1] | **41** | **40** | 80 | 79 |
| | **34,343** | **42,402** | 30,220 | 37,294 |
| **Liabilities and shareholders' equity** | | | | |
| Current liabilities | | | | |
| Bank indebtedness | **102** | **102** | 100 | 100 |
| Short-term borrowings | **548** | **548** | 326 | 326 |
| Accounts payable and other[4,6,9] | **3,722** | **4,904** | 2,688 | 3,811 |
| Interest payable[4] | **114** | **185** | 117 | 177 |
| Current maturities of long-term debt[4] | **252** | **354** | 154 | 185 |
| Current maturities of non-recourse long-term debt[6] | **122** | **103** | 70 | 68 |
| | **4,860** | **6,196** | 3,455 | 4,667 |
| Long-term debt[4,7,8] | **14,257** | **19,222** | 13,561 | 18,374 |
| Non-recourse long-term debt[6] | **951** | **606** | 1,061 | 701 |
| Other long-term liabilities[3,4,6,9] | **1,892** | **2,306** | 1,473 | 1,658 |
| Future income taxes[1,2,3,6,8] | **2,696** | **2,574** | 2,447 | 2,370 |
| | **24,656** | **30,904** | 21,997 | 27,770 |
| Redeemable noncontrolling interests[5] | **-** | **640** | - | 364 |
| Shareholders' equity | | | | |
| Share capital | | | | |
| Preference shares | **1,056** | **1,056** | 125 | 125 |
| Common shares | **3,969** | **3,969** | 3,683 | 3,683 |
| Contributed surplus | **106** | **-** | 59 | - |
| Retained earnings[1,2,3,5,8,9,12] | **4,991** | **4,172** | 4,734 | 3,977 |
| Additional paid-in capital[4] | **-** | **244** | - | 131 |
| Accumulated other comprehensive loss[3,12] | **(1,094)** | **(1,536)** | (882) | (1,026) |
| Reciprocal shareholding | **(187)** | **(187)** | (154) | (154) |
| Total Enbridge Inc. shareholders' equity | **8,841** | **7,718** | 7,565 | 6,736 |
| Noncontrolling interests[4,5] | **846** | **3,140** | 658 | 2,424 |
| | **9,687** | **10,858** | 8,223 | 9,160 |
| | **34,343** | **42,402** | 30,220 | 37,294 |

***1 Gain on Acquisition***

*At December 31, 2010 under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control was obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At December 31, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.*

*On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty Caverns was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of Hardisty Caverns, a $20 million gain, net of tax, was recorded in earnings for the year ended December 31, 2010 under U.S. GAAP.*

***2 Commodity Inventories Valuation***

*Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2011, lower of cost or market adjustments resulted in a $11 million (2010 - $32 million) decrease to inventory, a $4 million increase (2010 - $6 million decrease) to the future income tax liability and a $13 million increase (2010 - $4 million increase; 2009 - $24 million decrease) to earnings.*

***3 Pension Accounting***

*U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $704 million (2010 - $337 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $304 million (2010 - $138 million), a decrease in future tax liability of $114 million (2010 - $58 million) and a decrease in AOCI of $286 million (2010 - $141 million) at December 31, 2011.*

*Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $2 million (2010 - $3 million) increase to the net pension asset with an offset to retained earnings, and a $1 million decrease to earnings (2010 - $1 million; 2009 - $1 million).*

*Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $88 million (2010 - $85 million) decrease to regulatory assets with a corresponding decrease to retained earnings, and a $6 million decrease to earnings (2010 - $6 million; 2009 - $6 million).*

*Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows.*

| | **2011** | 2010 | 2009 |
|---|---|---|---|
| (millions of Canadian dollars) | | | |
| Prior service cost | **-** | 1 | - |
| Net loss | **10** | 7 | 5 |
| | **10** | 8 | 5 |

*Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:*

| | **2011** | 2010 | 2009 |
|---|---|---|---|
| (millions of Canadian dollars) | | | |
| Prior service cost | **3** | 4 | 1 |
| Accumulated net loss | **283** | 137 | 102 |
| | **286** | 141 | 103 |

*Net amounts reflected in OCI for the year are as follows:*

| | **2011** | 2010 | 2009 |
|---|---|---|---|
| (millions of Canadian dollars) | | | |
| Unamortized prior service cost | **(1)** | 3 | - |
| Net loss/(gain) | **146** | 35 | (10) |
| | **145** | 38 | (10) |

*The Company estimates that approximately $25 million related to pension and OPEB plans at December 31, 2011 will be reclassified into earnings in the next twelve months, as follows:*

| | Pension Benefits | OPEB | Total |
|---|---|---|---|
| (millions of Canadian dollars) | | | |
| Prior service costs | - | 1 | 1 |
| Loss | 22 | 2 | 24 |
| | 22 | 3 | 25 |

**4 Consolidation of a Limited Partnership**

*Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 23.0 % interest in the partnership, resulting in an increase to assets of $8,920 million (2010 - $7,972 million), an increase in liabilities of $6,398 million (2010 - $6,098 million) and an increase in noncontrolling interests of $2,519 million (2010 - $1,871 million) at December 31, 2011. During the year ended December 31, 2011, dilution gains of $88 million, net of tax of $53 million (2010 - $52 million, net of tax of $30 million) were reclassified from earnings to equity as a result of the consolidation of EEP.*

**5 Redeemable Noncontrolling Interests**

*Under Canadian GAAP, a subsidiary's redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the Consolidated Statements of Financial Position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At December 31, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $411 million (2010 - $255 million).*

**6 Accounting for Joint Ventures**

*Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the SEC, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.*

**7 Transaction Costs**

*Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-term debt. For U.S. GAAP, these costs are reclassified to Deferred amounts and other assets. As at December 31, 2011, $92 million (2010 - $89 million) of transaction costs were reclassified.*

**8 Common Control Transactions**

*U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At December 31, 2011, a decrease in assets of $408 million (2010 - $414 million), a decrease in liabilities of $54 million (2010 - $61 million), and a decrease in retained earnings of $354 million (2010 - $353 million), related to a historic transaction with the Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was a $1 million decrease to earnings (2010 - $1 million; 2009 - $1 million).*

**9 Accounting for Leases**

*The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company's pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $122 million (2010 - $129 million), an increase in liabilities of $114 million (2010 - $122 million), an increase in retained earnings of $8 million (2010 - $7 million) and an increase in earnings of $1 million (2010 - $1 million; 2009 - $1 million).*

**10 Unrecognized Tax Benefits**

| (millions of Canadian dollars) | **2011** | 2010 |
|---|---|---|
| Unrecognized tax benefits at beginning of year | **17** | 22 |
| Gross increases for tax positions of current year | **3** | 2 |
| Gross increases for tax positions of prior years | **-** | - |
| Gross decreases for tax positions of prior years | **(1)** | (2) |
| Reduction for lapse of statute of limitations | **(1)** | (2) |
| Changes in translation of foreign currency | **-** | - |
| Decreases relating to settlements with taxing authority | **-** | (3) |
| Unrecognized tax benefits at end of year | **18** | 17 |

*The unrecognized tax benefits at December 31, 2011, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.*

*The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2011 includes a $1 million expense (2010 - $2 million recovery; 2009 - $1 million expense) of interest and penalties. As at December 31, 2011, interest and penalties of $9 million (2010 - $8 million; 2009 - $10 million) have been accrued.*

*The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007 and all returns are generally closed through 2006. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2007.*

**11 Indefinite Reversal Rule**

*The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2011 were approximately $524 million (2010 - $491 million; 2009 - $406 million).*

***12 Unrealized Foreign Exchange Loss***

*Under Canadian GAAP, an unrealized foreign exchange loss in AOCI was recognized in earnings during the year ended December 31, 2011 due to a dividend paid by a subsidiary. Under U.S. GAAP, this foreign exchange loss should remain in AOCI until the subsidiary is sold. At December 31, 2011, this difference resulted in an increase to earnings of $155 million with a corresponding decrease in OCI. This difference did not result in an adjustment at December 31, 2010 or December 31, 2009.*

## FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

### Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

### Statement of Comprehensive Income

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

### Goodwill Impairment

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

### Balance Sheet Offsetting

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim beginning on or after January 1, 2013.

# APPLICANT SUBSIDIARIES

Please see Exhibit A1, Tab 11, Schedule 1, Corporate Organization Chart.

Witnesses: J. Jozsa
B. Yuzwa

# 10-K FILING - PARENT COMPANY

The parent company, Enbridge Inc., does not require a 10-K filing.

**Rating Report**
**Report Date:**
April 25, 2011
**Previous Report**
January 8, 2010

Insight beyond the rating.

# Enbridge Gas Distribution Inc.

**Analysts**
**Adeola Adebayo**
+1 416 597 7421
aadebayo@dbrs.com

**Yean (Kit) Kitnikone**
+1 416 597 7325
kkitnikone@dbrs.com

**The Company**
Enbridge Gas Distribution Inc. is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. The Company also distributes natural gas to approximately 15,000 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly-owned subsidiary of Enbridge Inc. (rated A (low)).

**CP Limit: $700 million**

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Commercial Paper | R-1 (low) | Confirmed | Stable |
| Unsecured Debentures & Medium-Term Notes | A | Confirmed | Stable |
| Cum. & Cum. Redeemable Convertible Preferred Shares | Pfd-2 (low) | Confirmed | Stable |

## Ratings Update

DBRS has today confirmed the Unsecured Debentures & Medium-Term Notes, Commercial Paper, and Cumulative & Cumulative Redeemable Convertible Preferred Share ratings of Enbridge Gas Distribution Inc. (EGD or the Company) at "A", R-1 (low) and Pfd-2 (low), respectively, all with Stable trends based on EGD's low business risk operations, stable regulatory environment, strong franchise area and stable financial profile. The regulatory environment remains reasonable and stable, allowing the Company to recover its operating expenses and capital expenditures in a timely fashion. The ratings also reflect the low allowed ROE under which the Company must operate until 2012.

EGD currently benefits from productivity enhancements and incremental revenues under a 2008 Ontario Energy Board (OEB) approved incentive regulation (IR) framework (from 2008 to 2012). While a subsequent OEB general cost of capital decision provides for an initial ROE of 9.75% to be incorporated into a utility's 2010 Cost of Service Application, EGD's ROE of 8.39% will remain unchanged throughout the IR period. In May 2010, the OEB issued a decision that the new ROE could not be used to calculate earnings sharing with ratepayers. The Company's appeal of that decision was heard by the Ontario Divisional court in January 2011, with a decision pending. The ROE increase will likely be positive for EGD when the IR is renewed in 2013. (Continued on page 2.)

## Rating Considerations

**Strengths**
(1) Low business risk operations with a stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics
(4) Price competitiveness of natural gas

**Challenges**
(1) Weather-related volume risk
(2) Significant seasonal liquidity requirements
(3) Moderate cash flow deficits due to increased capital expenditures
(4) Low allowed ROE

## Financial Information

| Enbridge Gas Distribution Inc. | For the 12 months ended | | | | |
|---|---|---|---|---|---|
| | Dec. 10 | Dec. 09 | Dec. 08 | Dec. 07 | Dec. 06 |
| EBIT interest coverage | 2.4 | 2.6 | 2.5 | 2.2 | 1.8 |
| Total debt/capital (incl intercompany loan) | 54.6% | 53.5% | 57.9% | 56.1% | 59.8% |
| Cash flow/adjusted total debt (1) | 17.5% | 19.3% | 15.3% | 14.5% | 9.1% |
| Cash flow/capital expenditures (times) | 1.3 | 1.4 | 1.2 | 1.1 | 0.7 |
| Approved ROE | 8.39% | 8.39% | 8.39% | 8.39% | 8.74% |
| Net income before extra items | 212 | 240 | 217 | 190 | 127 |
| Operating cash flow (CAD millions) | 484 | 519 | 490 | 418 | 282 |

(1) Includes note receivable from parent company and investment in affiliate company

**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

## Ratings Update (Continued from page 1.)

EGD's gas distribution margin declined modestly in 2010 by 2.9% but had increased year-over-year from F2006 through F2009 due to customer growth, favourable changes in customer mix and higher distribution rates as a result of the application to the IR formula approved by the OEB. In 2010, warmer weather was the primary driver of the modestly lower earnings when compared to 2009.

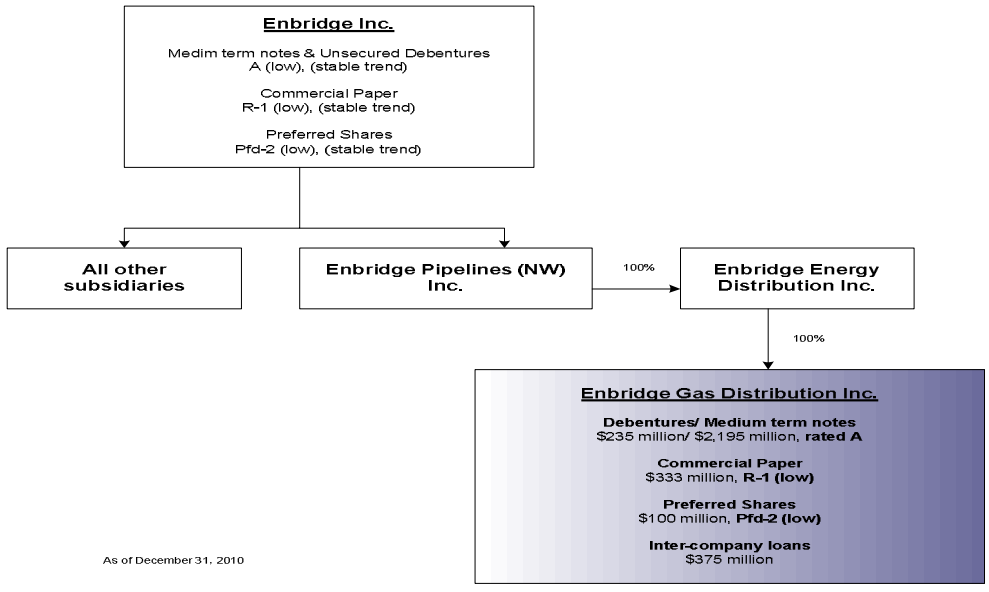
Customer growth however continues to be offset by lower average annual consumption. While the risk of fuel switching remains when natural gas prices are high (currently relatively low), natural gas is the predominant fuel of choice in the residential heating market in EGD's franchise area. Furthermore, natural gas has continued to provide price advantages over its primary competitors – domestic fuel oil and electricity.

For 2011, capital expenditures are expected to be approximately $500 million, having averaged $385 million annually in recent years, as the Company continues to invest in network expansion and upgrades to support customer growth, including lateral connections to new power generating facilities. Growth capex, which represents approximately 30% of capex, is expected to include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.

As a portion of capital expenditures are financed through short-term debt and later refinanced with long-term debt, continued access to the short- and long-term capital markets is important for EGD. DBRS believes the Company's financing of these capital projects will be done in a manner that ensures it maintains stable credit metrics going forward. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit profile and manage the regulatory approved capital structure.

The Company has very large and volatile seasonal liquidity requirements and usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. DBRS views the Company's current liquidity as adequate given the current low price gas environment, noting that a combination of cold weather and high gas prices could exhaust EGD's available liquidity.

## Simplified Organizational Chart



**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

## Rating Considerations Details

**Strengths**

(1) EGD's low risk business operations continue to generate reasonably stable operating cash flows, while operating in a stable regulatory environment where the Company has the opportunity to recover its operating expenses and capital expenditures in a timely manner, and is allowed to earn a reasonable return on its investments. The Company has limited exposure to commodity price risk as its gas purchase costs are passed on to customers through quarterly rate adjustments. Furthermore, the long-term IR framework provides incentives for improved efficiency and long-term regulatory stability.

(2) EGD is the largest regulated natural gas utility in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. Modest and continued growth in its customer base will allow the Company to continue to generate strong earnings and cash flows.

(3) EGD maintains a reasonable balance sheet and credit metrics, reflecting: (a) total debt-to-capital ratio of 55%; (b) EBIT interest coverage ratio of 2.4 times; and (c) cash flow-to-debt ratio of 17.5%. The variability in cash flows and credit metrics year-over-year has been largely due to the impact of weather, seasonality of the gas distribution business and natural gas prices. The Company's credit metrics remain adequate for the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 36%.

(4) Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area and maintains both a price and environmental advantage relative to its primary competition, domestic fuel oil and electricity.

**Challenges**

(1) Weather remains the most significant risk, as forecast volumes, which are based on the normalized weather, are built into the Company's base rates, while actual usage varies with weather. Therefore, colder than normal weather would generally result in higher earnings compared to periods of warmer than normal weather. The years 2007 through 2009 were colder than normal and resulted in higher earnings for EGD when compared with 2010 which was warmer than normal.

(2) The Company has very large and volatile seasonal liquidity requirements, which has strained its available liquidity in the past. The Company's usage of its credit facility remains high in the third and fourth quarter of the year as gas storage increases for the winter months. As such, favourable access to the short- and long-term capital market remains important.

(3) Free cash flow deficits are expected to be modest over the medium term, mainly attributable to the Company's capital expenditures associated with unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives. EGD is expected to finance these deficits through debt issuances and management of dividend payments to (or equity injections from) the parent, so as to maintain the debt-to-capital ratio within the regulatory approved level of 64%.

(4) The IR framework has set a low base level for EGD's allowed ROE at 8.39% until year-end 2012. Thus, while the Company has the opportunity to earn higher returns, any upside is capped by the nature of the IR mechanism. Low ROEs have a negative impact on earnings and cash flow, although an increasing rate base would partially mitigate this impact.

**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

# Earnings and Outlook

| | For the 12 months ended | | | | |
|---|---|---|---|---|---|
| (CAD millions) | Dec. 10 | Dec. 09 | Dec. 08 | Dec. 07 | Dec. 06 |
| Net gas distribution revenue | 605 | 576 | 506 | 485 | 377 |
| Gas transportation service revenue | 390 | 449 | 505 | 500 | 493 |
| Gas distribution margin | 995 | 1,025 | 1,011 | 985 | 870 |
| Other revenue | 108 | 108 | 94 | 81 | 59 |
| Total revenue | 1,103 | 1,133 | 1,105 | 1,066 | 928 |
| EBITDA (incl. income from affiliates) | 729 | 761 | 746 | 707 | 586 |
| EBIT (incl. income from affiliates) | 459 | 507 | 507 | 479 | 373 |
| Gross interest expense | 189 | 195 | 206 | 214 | 207 |
| Net income before extra. Items | 212 | 240 | 217 | 190 | 127 |
| Extraordinary items | (19) | (19) | (6) | 0 | 0 |
| Preferred dividends | (2) | (3) | (5) | (5) | (5) |
| Total | 191 | 218 | 207 | 185 | 122 |
| | | | | | |
| Return on equity | 11.5% | 12.9% | 12.0% | 11.2% | 7.9% |
| EBIT margin | 35.9% | 39.2% | 40.3% | 39.0% | 33.4% |

## Summary

- EGD's EBIT and EBITDA have remained stable over the past four years, and remained strong in 2010 primarily due to higher customer additions, favourable changes in customer mix and higher distribution charges, offset by warmer weather.
- EGD is expected to share excess earnings with customers under the current IR terms. The earnings sharing formula allows for earnings in excess of the annual adjusted ROE plus 100 basis points (bps) to be shared 50/50 with ratepayers. The Company's proportional estimate of earnings sharing was $19 million for 2010, subject to OEB approval in 2011.
- Transportation revenue has remained generally stable and represents 40% to 50% of the Company's gas distribution margins. EGD continues to monitor and take measures to mitigate potential weakness in the financial position of its large industrial customers.
- Interest expense has continued to decline modestly over the past few years with lower short-term borrowings as a result of lower gas prices.

## Outlook

- The Company's earnings, under normal weather conditions, should grow moderately over the medium term, driven primarily by customer and economic growth in the Company's franchise areas and the continued competitiveness of natural gas. The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Though EGD's request to the OEB for approval to use the new base level ROE of approximately 9.85% to determine the annual earnings sharing with customers for 2010 and the remainder of the IR was denied, the Company anticipates applying the then-current ROE to determine rates after the conclusion of the IR terms, effective for the rate year beginning 2013. EGD has appealed the OEB ruling, with a decision pending.

**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

# Financial Profile

| Statement of Cash Flow | Dec 31 | Dec 31 | Dec 31 | Dec 31 | Dec 31 |
|---|---|---|---|---|---|
| (CAD millions) | 2010 | 2009 | 2008 | 2007 | 2006 |
| Net income (after pfd dividends) | 210 | 237 | 212 | 185 | 122 |
| Depreciation & amortization | 270 | 254 | 239 | 228 | 213 |
| Non-cash charges & deferred income taxes | 4 | 29 | 39 | 5 | (53) |
| **Cash Flow From Operations** | 484 | 519 | 490 | 418 | 282 |
| Capital expenditures | (365) | (370) | (411) | (385) | (393) |
| Dividends to the parent | (208) | (181) | (158) | (65) | (175) |
| **Free Cash Flow Before W/C Changes** | (89) | (32) | (80) | (32) | (285) |
| Working capital changes | 31 | 467 | (125) | 133 | 181 |
| **Net Free Cash Flow** | (58) | 436 | (205) | 101 | (104) |
| Acquisitions/Divestitures | 0 | 0 | 0 | 0 | 0 |
| Other/adjustment | 0 | (14) | 5 | (12) | (30) |
| Cash flow before financing | (58) | 422 | (200) | 89 | (135) |
| Net change in debt financing | 69 | (470) | 261 | (167) | 136 |
| Net change in pfd equity financing | 0 | 0 | 0 | 0 | 0 |
| Net change in common equity | 0 | 0 | 0 | 88 | 0 |
| Other/adjustment | (16) | (21) | | | |
| Net change in cash flows | (5) | (68) | 60 | 10 | 1 |

| Key Figures and Ratios | Dec 31 2010 | Dec 31 2009 | Dec 31 2008 | Dec 31 2007 | Dec 31 2006 |
|---|---|---|---|---|---|
| ST debt (millions) | 500 | 677 | 1,026 | 826 | 831 |
| LT debt (millions) | 2,267 | 2,015 | 2,167 | 2,064 | 2,258 |
| Inter-company debt ($ millions) | 375 | 375 | 375 | 375 | 375 |
| | | | | | |
| Total debt/capital (incl intercompany loan) | 54.6% | 53.5% | 57.9% | 56.1% | 59.8% |
| Total debt/capital (excl. intercompany loan) | 59.2% | 58.1% | 62.3% | 60.8% | 64.7% |
| EBIT interest coverage (incl. intercompany loan) (1) | 2.4 | 2.6 | 2.5 | 2.2 | 1.8 |
| EBIT interest coverage (excl. intercompany loan) | 2.4 | 2.6 | 2.5 | 2.2 | 1.7 |
| Cash flow/total adjusted debt (1) | 17.5% | 19.3% | 15.3% | 14.5% | 9.1% |
| Cash flow/adjusted long-term debt (1) | 20.0% | 24.0% | 21.6% | 17.9% | 12.5% |
| Dividend payout ratio | 99.1% | 76.6% | 75.1% | 36.9% | 141.1% |
| Fixed charges coverage (times) | 2.4 | 2.5 | 2.4 | 2.2 | 1.7 |

(1) Includes note receivable from parent company and investment in affiliate company.

## Summary

- Cash flow from operations was sufficient to cover both dividends paid to the parent and estimated maintenance capital expenditures in 2009 and 2010. Credit metrics are expected to come under modest pressure from increasing capital expenditures.
- The Company's credit metrics remain consistent with the current rating category.
- EGD has a targeted dividend payment of 90% to 100% subject to maintaining a capital structure in line with regulatory levels.

## Outlook

- DBRS expects EGD to generate modest free cash flow deficits due to capital expenditures in the medium term, which will be funded with a combination of debt and dividend management in order to maintain its credit metrics and manage the regulated approved capital structure.
- Capital expenditures (including growth) in 2011 are expected to increase to $500 million from current levels as the Company continues to invest in maintenance, network expansion and upgrades to support customer growth. Capital projects for 2011 include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives.
    - Deregulation of new natural gas storage has created a growth opportunity for EGD, as a result the Company expanded its storage capacity in 2010 by 8% and sold unregulated storage services into the storage market.

**Enbridge Gas Distribution Inc.**

**Report Date:**
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- EGD continues to have strong access to the short- and long-term capital markets. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain the stability of its credit metrics.

## Long-Term Debt Maturities and Liquidity

**Long Term debt**

| (CAD millions) | Average Coupon | Maturity | Dec. 31, 2010 | Dec. 31, 2009 |
|---|---|---|---|---|
| Debentures | 10.46% | 2011-2024 | 235 | 385 |
| Medium-term notes | 5.54% | 2011-2036 | 2,195 | 1,795 |
| Other | | | 6 | 12 |
| Total long-term debt | | | 2,436 | 2,192 |
| Loans from affiliate | | | 375 | 375 |

| **Debt Maturity schedule** | Less than 1 year | 1-3 years | 3-5 years | Thereafter | Total |
|---|---|---|---|---|---|
| As at Dec. 31, 2010 (CAD millions) | 150 | 0 | 400 | 1,880 | 2,430 |

- EGD's debt repayment schedule remains manageable, with only $150 million maturing within the next three years.
- As of December 31, 2010, EGD had issued $2,195 million of medium-term notes (MTNs) at an average coupon rate of 5.54%.
- EGD is subject to an EBIT interest covenant in order to issue additional indebtedness. EBIT for any 12 consecutive months out of the previous 23 months must be at least two times its annual pro forma interest requirements for all debt that has a maturity term longer than 18 months. The covenant does not apply to debt issuance for refinancing and interest expenses do not include short-term interest expenses. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. The Company was in compliance with the test at fiscal year end 2010.

**Inter-company debt**

- As of December 31, 2010, EGD owned $825 million of non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid by either cash or non-retractable preferred shares of the Company. DBRS treats this entire amount as debt and does not assign any equity treatment to the securities.

**Bank Lines/Liquidity**

| **Credit facilities** | | | | | As at Dec. 31, 2010 |
|---|---|---|---|---|---|
| | **Amount** | **Drawn** | **Commercial Paper** | **Available** | **Expiry date** |
| Committed lines of credit | 700.0 | 0.0 | 350.0 | 350.0 | Sep. 2011 |
| Uncommitted lines of credit* | 12.0 | 8.0 | 0.0 | 4.0 | |
| **Total** | **712.0** | **8.0** | **350.0** | **354.0** | |

* The uncommitted lines of credit are at St. Lawrence Gas.

| (CAD millions) | Dec. 10 | Sep. 10 | Jun. 10 | Mar. 10 | Dec. 09 |
|---|---|---|---|---|---|
| **Short term debt usage** | 350 | 445 | 157 | 260 | 527 |

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capital expenditures. Working capital requirements are very seasonal and are also heavily

influenced by the volatility of gas prices. These fluctuating capital requirements are mainly supported by the Company's commercial paper (CP) program.

- The Company has a $700 million CP program of which $350 million was available at the end of 2010. The CP program is fully backed by a $700 million 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate, given the current low gas price environment; nevertheless, the Company remains exposed to gas price volatility. A combination of cold weather and high gas prices could exhaust the Company's available liquidity, however, this is unlikely given the relatively current low gas price environment.

## Regulation

**Regulatory Overview**
The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly rate adjustments. Therefore, the Company's distribution margin is not impacted by the gas purchase cost.

**Gas Distribution**
In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan to a maximum of an additional two years.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the Cost of Service methodology utilized in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The Company's 2010 ROE of 8.39% will remain unchanged throughout the IR period. The equity component also remains at 36%. The gas commodity and upstream transportation costs will continue to be passed on to customers.

The OEB recently reviewed the current methodology for adjusting cost of capital for regulated entities starting in the 2010 rate year. The decision maintains a formulaic approach to setting ROE levels; however, the existing formula will be reset to address the relatively low current ROE level, and refined to reduce sensitivity to changes in government bond yields. This new approach will provide an initial ROE of 9.75% (since revised to 9.58%) to be incorporated in 2010 Cost of Service applications. For EGD, the full benefit of the higher allowed ROE is expected to be captured on renewal of the IR in 2013. In January 2011, the Ontario Division Court heard EGD's appeal of the OEB's decision not to adjust the 8.39% ROE in its IR settlement to the revised 9.75% regulated ROE for the purposes of EGD's IR earnings sharing formula. The sharing formula allows earnings in excess of the annual adjusted ROE, plus 100 bps, to be shared 50/50 with ratepayers. The Division Court decision is pending.

The key terms of the OEB approved IR framework (effective January 2008) are summarized as follows:

- *Revenue Per Customer Cap* – The settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize the Company's exposure to declining average use of natural gas while providing an incentive for the Company to continue growing its customer base.

- *Revenue Escalation Factor* – The revenue escalation factor is comprised of an inflation component and an adjustment for customer growth. In addition to the annual inflation adjustment, revenues will also grow by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors is forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

- *Earnings Sharing* – To align the interests of customers with the Company's shareholders, an earnings sharing mechanism forms part of the settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e., excluding the effects of weather) exceeds the allowed utility return on equity (adjusted in accordance with provisions in the IR agreement), earnings will be shared with customers. The shareholders will retain the first 100 bps of ROE above the allowed ROE, while earnings represented by the ROE in excess of 100 bps above the allowed ROE will be shared equally with customers.

- *Adjustments* – There are several cost and deferral accounts that fall outside of the revenue escalation formula. The settlement provides for the recovery of capital invested in new power generation laterals, which is important given the significant capital requirements for such projects and their importance to Ontario's electricity needs. The Company is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

- *Off Ramps* – An OEB review will be triggered if the Company's ROE varies more than 300 bps (either negatively or positively) relative to the allowed ROE. The review will determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the settlement or a return to Cost of Service regulation. The review will not have an impact on earnings for prior years. The settlement does not preclude the Company from applying to the OEB for an increase in the embedded allowed ROE.

**Gas Storage**

EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB changed EGD's pricing policy in 2007.

**Gas Distribution – New York**

The Company owns St Lawrence Gas Company, which provides natural gas distribution services to 15,000 customers in New York State. The regulatory framework in New York is viewed as stable.

**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

## Enbridge Gas Distribution Inc.

**Balance Sheet**

| (CAD millions) | Dec. 31 2010 | Dec. 31 2009 | Dec. 31 2008 | | Dec. 31 2010 | Dec. 31 2009 | Dec. 31 2008 |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | **Liabilities & Equity** | | | |
| Cash + equivalents | - | - | 100 | S.t. & l.t.d. due 1yr. | 500 | 677 | 1,026 |
| Accounts receivable | 802 | 769 | 980 | A/P, accr'ds. & other | 841 | 786 | 755 |
| Gas in storage | 400 | 396 | 656 | **Current Liabilities** | 1,341 | 1,463 | 1,781 |
| Other current assets | - | 33 | 23 | Def'd. taxes + credits | 1,229 | 1,157 | 14 |
| **Current Assets** | 1,202 | 1,197 | 1,759 | Long-term debt | 2,267 | 2,015 | 2,167 |
| Net fixed assets | 4,458 | 4,290 | 3,514 | Loans from affiliate | 375 | 375 | 375 |
| Other assets | 654 | 666 | 186 | Perpetual pfds. | 100 | 100 | 100 |
| Investments in affiliate | 825 | 825 | 825 | Shareholders' equity | 1,827 | 1,867 | 1,848 |
| **Total** | 7,139 | 6,978 | 6,285 | **Total** | 7,139 | 6,978 | 6,285 |

| **Ratio Analysis** | Dec 31 | Dec 31 | Dec 31 | Dec 31 | Dec 31 |
|---|---|---|---|---|---|
| **Liquidity Ratios** | 2010 | 2009 | 2008 | 2007 | 2006 |
| Current ratio | .90x | .82x | .99x | .98x | 1.08x |
| Accumulated depreciation/gross fixed assets | 25.5% | 25.0% | 36.0% | 35.6% | 34.7% |
| Cash flow/capital expenditures | 1.33x | 1.40x | 1.19x | 1.09x | 0.72x |
| Cash flow-dividends/capital expenditures | 0.76x | 0.91x | 0.81x | 0.92x | 0.27x |
| Cash flow/adjusted debt (1) | 17.5% | 19.3% | 15.3% | 14.5% | 9.1% |
| Total debt/capital (incl intercompany loan) | 54.6% | 53.5% | 57.9% | 56.1% | 59.8% |
| Total debt/capital (excl. intercompany loan) | 59.2% | 58.1% | 62.3% | 60.8% | 64.7% |
| Deemed equity | 36% | 36% | 36% | 36% | 35% |
| Dividend payout ratio | 99.1% | 76.6% | 75.1% | 36.9% | 141.1% |
| **Coverage Ratios** | | | | | |
| EBITDA interest coverage (1) | 3.86x | 3.91x | 3.63x | 3.31x | 2.83x |
| EBIT interest coverage (1) | 2.43x | 2.60x | 2.46x | 2.24x | 1.80x |
| Fixed-charges coverage | 2.39x | 2.54x | 2.38x | 2.16x | 1.74x |
| Debt/EBITDA | 3.80x | 3.54x | 4.28x | 4.09x | 5.27x |
| **Earnings Quality/Operating Efficiencies & Statistics** | | | | | |
| Operating margin | 35.9% | 39.2% | 40.3% | 39.0% | 33.4% |
| Net margin | 19.2% | 21.2% | 19.7% | 17.8% | 13.7% |
| Return on common equity | 11.5% | 12.9% | 12.0% | 11.2% | 7.9% |
| Approved ROE | 8.39% | 8.39% | 8.39% | 8.39% | 8.74% |
| Degree day deficiency - % normal | 97.7% | 107.2% | 107.3% | 101.2% | 89.6% |
| Customer growth | 2.0% | 2.0% | 2.0% | 2.3% | 3.7% |

(1) Includes note receivable from parent company and investment in affiliate company.

**Enbridge Gas Distribution Inc.**

**Report Date:**
April 25, 2011

## Rating

| Debt Rated | Rating | Rating Action | Trend |
|---|---|---|---|
| Commercial Paper | R-1 (low) | Confirmed | Stable |
| Unsecured Debentures & Medium-Term Notes | A | Confirmed | Stable |
| Cum. & Cum. Redeemable Convertible Preferred Shares | Pfd-2 (low) | Confirmed | Stable |

## Rating History

| Debt Rated | Current | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|
| Commercial Paper | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) |
| Unsecured Debentures & Medium-Term Notes | A | A | A | A | A | A |
| Cum. & Cum. Redeemable Convertible Preferred Shares | Pfd-2 (low) | Pfd-2 (low) | Pfd-2 (low) | Pfd-2 (low) | Pfd-2 (low) | Pfd-2 (low) |

Notes:
All figures are in Canadian dollars unless otherwise noted.

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Global Credit Portal
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March 23, 2011

**Research Update:**

# Enbridge Inc, Enbridge Pipelines Inc, And Enbridge Gas Distribution Inc. Outlooks Revised To Negative; Ratings Affirmed

**Primary Credit Analyst:**
Gavin MacFarlane, Toronto (1) 416-507-2545;gavin_macfarlane@standardandpoors.com

**Secondary Contact:**
Nicole Martin, Toronto (1) 416-507-2560;nicole_martin@standardandpoors.com

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**Research Update:**

# Enbridge Inc, Enbridge Pipelines Inc, And Enbridge Gas Distribution Inc. Outlooks Revised To Negative; Ratings Affirmed

## Overview

- We are revising our outlook on Enbridge Inc. (EI), Enbridge Pipelines Inc., and Enbridge Gas Distribution Inc. to negative from stable.
- We are affirming our ratings, including our 'A-' long-term corporate credit ratings, on the three companies.
- The proposed competitive toll settlement will increase the business risk of the Enbridge system which accounts for approximately one-third of EI's adjusted earnings.
- Credit metrics, which we have previously indicated are weak, may not be sufficient to support the increase in business risk at the current rating.
- The affirmation reflects our view of significant long-term and predictable cash flows and a strong competitive position.

## Rating Action

On March 23, 2011, Standard & Poor's Ratings Services revised its outlook on Enbridge Inc. (EI), Enbridge Pipelines Inc. (EPI), and Enbridge Gas Distribution Inc. (EGD) to negative from stable. At the same time, Standard & Poor's affirmed its ratings, including its 'A-' long-term corporate credit ratings, on the three companies.

The outlook revision reflects our view of the increased business risk associated with the terms of the proposed competitive toll settlement (CTS) and credit metrics that may not be sufficient in the near term to support the change in business risk.

## Rationale

The proposed CTS increases the business risk on EI's Enbridge system, which accounts for approximately one-third of the parent's 2010 adjusted earnings. The terms of the proposed CTS exposes the parent company to volume risks and variability in operating costs, among other risks. Standard & Poor's notes that the CTS has some risk mitigation for EI, including volume thresholds and protection for material change in business conditions. Credit metrics, which we have previously indicated are low for the ratings, might not show sufficient improvement from our previous expectations to support the increase in business risk. The increase in business risk associated with the implementation of the CTS is an overall marginal increase in risk to EI and we



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expect the parent's business risk profile to remain in the excellent category.

The negative outlook on EPI mirrors that on EI. EPI owns the Enbridge system. Given the intercorporate links to the parent, the outlook on EGD also reflects that on EI.

The ratings on EI, EPI, and EGD reflect Standard & Poor's view of an excellent business risk profile, which the strong market position of the core liquids pipelines and gas distributions businesses, its significant long-term and regulated cash flows, and the companies' conservative approach to risk management all support. Offsetting these is a financial risk profile that we view as significant, reflecting high leverage.

EI is a holding company with wholly and partially owned subsidiaries that focus primarily on owning and operating natural gas and oil pipelines in North America. The company's subsidiary, EPI, owns and operates the Enbridge system while EGD leads its gas distribution businesses. Liquids pipelines provide about 52% of the group's adjusted earnings, and EGD and returns from other gas distribution assets represent approximately 17%. Sponsored investments account for a further 21% of earnings while gas pipelines, processing, and energy services make up the rest. EI had C$15 billion in consolidated debt (Standard & Poor's-adjusted) at Dec. 31, 2010.

## Outlook

The negative outlook reflects our view that credit metrics are low for the rating. A deterioration in adjusted funds from operations-to-debt below 13% would likely result in a downgrade. Deterioration in the business risk profile could also lead to a lower rating. Credit metrics sustained at or above current levels would likely result in us revising the outlook to stable.

For more information on Enbridge Inc., Enbridge Pipelines Inc., and Enbridge Gas Distribution Inc., see the analyses published Dec. 29, 2010, on RatingsDirect on the Global Credit Portal.

## Related Criteria And Research

- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

## Ratings List

Outlook Revised To Negative

| | To | From |
|---|---|---|



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| | | |
|---|---|---|
| Enbridge Inc. | | |
| Enbridge Gas Distribution Inc. | | |
| Enbridge Pipelines Inc. | | |
| Corporate credit rating | A-/Negative/-- | A-/Stable/-- |

Ratings Affirmed

| | |
|---|---|
| Enbridge Inc. | |
| Enbridge Gas Distribution Inc. | |
| Senior unsecured debt | A- |
| Preferred stock | |
| Global scale | BBB |
| Canada scale | P-2 |
| Commercial paper | |
| Canada scale | A-1(Low) |

| | |
|---|---|
| Enbridge Pipelines Inc. | |
| Senior unsecured debt | A- |
| Commercial paper | |
| Canada scale | A-1(Low) |

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.



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The McGraw-Hill Companies

**Base Shelf Prospectus**

*No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.*

*This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this short form prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.*

*This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities offered hereby have not been and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold in the United States of America. See "Plan of Distribution".*

***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Enbridge Gas Distribution Inc. at 500 Consumers Road, Toronto, Ontario M2J 1P8 (telephone (416) 495-5922) and are also available electronically at www.sedar.com.*

# SHORT FORM BASE SHELF PROSPECTUS

**NEW ISSUE** **November 16, 2010**

**ENBRIDGE GAS DISTRIBUTION INC.**
**$800,000,000**
**MEDIUM TERM NOTES**
**(UNSECURED)**

Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Corporation") may from time to time issue medium term notes (the "Notes") due not less than one year from the date of issue at prices and on terms determined at the time of issue, in an aggregate principal amount of up to $800 million (or the equivalent in foreign currencies) during the twenty-five month period that this short form prospectus ("Prospectus"), including any amendments hereto, remains valid. This offering is a continuation of the Corporation's medium term note program, which was last renewed on May 28, 2008. As of the date of this Prospectus, a total of $2.18 billion principal amount of Notes have been issued and are outstanding. The up to $800 million principal amount of Notes offered hereunder is in addition to such previously issued Notes. The Notes will be issued under a trust indenture and will be direct, unsecured obligations of the Corporation ranking equally and *pari passu* except as to redemption and/or sinking fund provisions, with all other unsecured and unsubordinated indebtedness of the Corporation.

The specific variable terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, date(s) of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof) and interest payment date(s), redemption provisions (if redeemable), proceeds to the Corporation, the agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth in a pricing supplement (a "Pricing Supplement") or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus. Notes will be interest-bearing.

**There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".**

**In the opinion of counsel to the Corporation, the Notes offered hereby, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) for certain investors as referred to under the heading "Eligibility for Investment".**

**RATES ON APPLICATION**

The Notes will be offered severally by RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc. or other investment dealers selected from time to time by the Corporation, acting as agents of the Corporation or underwriters retained by the Corporation (individually, an "Agent" and collectively, the "Agents") in Canada, subject to confirmation by the Corporation pursuant to a selling agency agreement referred to under the heading "Plan of Distribution". The Corporation will pay to each Agent through whom any Note is sold a commission, in an amount to be determined from time to time by mutual agreement, but which will not exceed 0.75% of the principal amount of any Note, unless the Corporation and the Agent otherwise agree. The Notes may also be purchased from time to time by any of the Agents as principal, at such prices and with such commissions as may be agreed between the Corporation and any such Agents, for resale to the public at prices to be negotiated with each purchaser, which prices may vary during the distribution period and as between purchasers. Each Agent's compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as principal, to the Corporation. In connection with any offering

of Notes, the Agents may over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. See "Plan of Distribution". The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, in which case no commissions will be paid to the Agents.

**Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents, as each is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution which has extended credit facilities to the Corporation or one or more related issuers of the Corporation. See "Plan of Distribution".**

The offering of Notes is subject to approval of certain legal matters on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Fraser Milner Casgrain LLP**.**

The head and registered office of the Corporation is located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

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## DOCUMENTS INCORPORATED BY REFERENCE

The following documents, filed with the securities commission or similar authority in each of the provinces of Canada, are specifically incorporated by reference in, and form an integral part of, this Prospectus provided that such documents are not incorporated by reference to the extent that their contents are modified or superseded by a statement contained in this Prospectus or in any other subsequently filed document that is also incorporated by reference in this Prospectus:

(a) Consolidated comparative financial statements of the Corporation for the year ended December 31, 2009 and the auditors' report thereon;

(b) Management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2009;

(c) Consolidated comparative interim unaudited financial statements of the Corporation for the three and nine month periods ended September 30, 2010;

(d) Management's discussion and analysis of financial condition and results of operations for the three and nine month periods ended September 30, 2010; and

(e) Annual Information Form of the Corporation dated February 18, 2010 (the "AIF").

Any documents of the type referred to above, including any interim financial statements and related management's discussion and analysis, any material change reports (except confidential material change reports), any business acquisition reports and any exhibits to interim unaudited financial statements which contain updated earnings coverage calculations filed by the Corporation with the various securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the termination of this offering shall be deemed to be incorporated by reference into this Prospectus.

**Upon a new annual information form and the related annual financial statements and management's discussion and analysis being filed by the Corporation with and, where required, accepted by the applicable securities regulatory authorities during the term of this Prospectus, the previous annual information form, the previous annual financial statements, all interim financial statements and accompanying management's discussion and analysis, material change reports and business acquisition reports filed by the Corporation prior to the commencement of the financial year of the Corporation in respect of which the new annual information form is filed shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder. Upon interim financial statements and the accompanying management's discussion and analysis being filed by the Corporation with the applicable securities regulatory authorities during the term of this Prospectus, all interim financial statements and the accompanying management's discussion and analysis filed prior to the new interim**

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**financial statements shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder.**

Any statement contained in this Prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded, for purposes of this Prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of such a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute part of this Prospectus.

A Pricing Supplement or other prospectus supplement containing the specific terms of an offering of Notes will be delivered to purchasers of such Notes together with this Prospectus and will be deemed to be incorporated by reference into this Prospectus as of the date of such supplement solely for the purposes of the offering of the Notes offered thereunder.

Updated earnings coverage ratios will be filed quarterly with the applicable securities regulatory authorities, either as exhibits to the Corporation's unaudited interim and audited annual financial statements or as prospectus supplements and will be deemed to be incorporated by reference into this Prospectus for the purposes of the offering of the Notes.

## FORWARD LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Prospectus, including documents incorporated by reference into this Prospectus, to provide readers with information about the Corporation and its subsidiaries, including management's assessment of the Corporation's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this Prospectus include, but are not limited to, statements with respect to expected capital expenditures.

Although the Corporation believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Corporation's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Corporation's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Corporation operates, may impact levels of demand for the Corporation's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

The Corporation's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates and commodity prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this Prospectus and in documents incorporated by reference into this Prospectus. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Corporation's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Corporation assumes no obligation to publicly update

or revise any forward-looking statements made in this Prospectus or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

## THE CORPORATION

Enbridge Gas Distribution is an indirect wholly-owned subsidiary of Enbridge Inc. ("Enbridge"). Enbridge Energy Distribution Inc. ("EEDI"), itself an indirect wholly owned subsidiary of Enbridge, owns all of the issued and outstanding common shares of Enbridge Gas Distribution.

Enbridge Gas Distribution is a rate regulated natural gas distribution utility serving approximately 1.9 million residential, commercial and industrial customers. There are four principal interrelated aspects of the natural gas distribution business in which the Corporation is directly involved: distribution service, gas supply, transportation and storage.

The main areas in which the Corporation's customers are located are central and eastern Ontario, including Toronto and the surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, Enbridge Gas Distribution serves Massena, Ogdensburg, Potsdam and surrounding areas in northern New York State through St. Lawrence Gas Company, Inc. ("St. Lawrence"), a wholly owned subsidiary of the Corporation.

The utility business is conducted under statutes and municipal by-laws, which grant the right to operate in the areas served. Various aspects of the utility operations in Ontario are regulated by the Ontario Energy Board (the "OEB") with similar regulation applying to St. Lawrence by way of the New York State Public Service Commission.

Enbridge Gas Distribution was incorporated in 1848 by *Special Act*, II Victoria Cap. XIV, of the Province of Canada. By letters patent dated September 30, 1954, Enbridge Gas Distribution was continued under the *Corporations Act*, 1953 (Ontario) and is now subject to the *Business Corporations Act* (Ontario).

Enbridge Gas Distribution's registered office and principal place of business is located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

## USE OF PROCEEDS

The aggregate principal amount of the Notes offered under this Prospectus shall not exceed $800 million in Canadian currency or equivalent thereof in foreign currencies. The net proceeds to be received by the Corporation from the sale from time to time of Notes under this Prospectus will be the issue price thereof less any commissions and expenses paid in connection therewith. The net proceeds cannot be estimated as at the date hereof since the amount thereof will depend on the terms and conditions of the Notes and the extent to which Notes are issued under this Prospectus. The net proceeds from the sale of the Notes will be added to the general funds of the Corporation to be used for general corporate purposes, which may include reducing outstanding indebtedness and financing capital expenditures, investments and working capital requirements of the Corporation. The Corporation may, from time to time, issue debt instruments and incur additional indebtedness otherwise than through the issue of Notes pursuant to this Prospectus.

The net proceeds to be received by the Corporation from the sale of Notes from time to time under this Prospectus are not expected to be applied to fund any specific project. The Corporation's overall corporate strategy and major initiatives supporting its strategy are summarized in the Corporation's management's discussion and analysis for the year ended December 31, 2009, as modified or superseded by information contained in the Corporation's management's discussion and analysis for the three and nine month periods ended September 30, 2010, and subsequent periods, incorporated herein by reference.

## PLAN OF DISTRIBUTION

Pursuant to the terms of a selling agency agreement (the "Agency Agreement") dated November 16, 2010 between the Corporation and the Agents, the Agents are or will be authorized, as agents of the Corporation for this purpose only, to solicit offers to purchase Notes, directly or through other Canadian investment dealers. The Corporation will pay each Agent through whom any Note is sold a commission as set forth in Schedule "A" of the Agency Agreement, unless the Corporation and the Agent otherwise agree.

The Agency Agreement also provides that Notes may be purchased from time to time by any of the Agents as underwriter or principal, at a price to be agreed between the Corporation and the Agent, for resale to other dealers or

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purchasers at prices to be negotiated with each such investment dealer or purchaser. Such resale prices may vary during the distribution period and as between purchasers. Commissions may be paid in connection with such purchases in such amounts as may be agreed between the Corporation and any such Agent. The Agent's compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as underwriter or principal, to the Corporation.

The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commission will be paid to the Agents.

The Notes have not been and will not be registered under the *United States Securities Act* of 1933, as amended (the "Securities Act"), and may not be offered, sold or delivered in the United States or to, or for the account or benefit of, U.S. persons (as defined in Regulation S under the Securities Act) except in transactions exempt from the registration requirements of the Securities Act pursuant to Rule 144A thereunder. The Agents have severally agreed that they will not offer or sell the Notes in the United States, except in such an exempt transaction. In addition, until 40 days after the commencement of the offering of any Notes, an offer or sale of any such Notes within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with an applicable exemption from the registration requirements of the Securities Act.

In connection with any offering of Notes, the Agents may over allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Agents may purchase and sell Notes from time to time in the secondary market but are not obligated to do so. There can be no assurance that there will be a secondary market for the Notes. The offering price and other selling terms for such sales in the secondary market may, from time to time, be varied by the Agents.

The Corporation and, if applicable, the Agents, reserve the right to reject any offer to purchase Notes in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of Notes hereunder without notice.

Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents as each of the Agents other than Merrill Lynch Canada Inc. and Desjardins Securities Inc. is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution (collectively, the "EGDI Banks") which has extended a credit facility to the Corporation and each of the Agents is a directly or indirectly wholly-owned or majority owned subsidiary of a Canadian chartered bank or financial institution (collectively, the "Banks") which has extended credit facilities to one or more related issuers of the Corporation. The Corporation's credit facility with the EGDI Banks consists of a $700 million syndicated 364-day revolving facility. All such credit facilities are unsecured and each borrower thereunder is and has been since the establishment thereof, in compliance with the terms of the agreements governing them. The financial position of each of the Corporation and each other borrower under such credit facilities has not adversely changed in any material manner since the respective credit facility was put in place. The principal purpose of these credit facilities is to finance the near term growth capital expenditures and to support repayment obligations under commercial paper programs. The Corporation may incur additional indebtedness to the EGDI Banks under its credit facility and net proceeds received pursuant to offerings under this Prospectus may be used, directly or indirectly, to reduce that indebtedness. None of the Banks were involved in the decision to offer the Notes and none will be involved in the determination of the terms of the distribution of the Notes. As a consequence of the sale of the Notes through any of the Agents from time to time under this Prospectus, the Corporation will pay a commission to each Agent through which a Note is sold.

## DESCRIPTION OF NOTES

***The following description of the Notes is a summary of their material attributes and characteristics which does not purport to be complete. Certain of the capitalized terms used but not defined in this section have the meanings set out in Schedule A hereto. The terms and conditions set forth in this section will apply to each Note unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement. For further particulars of the terms of the Notes, reference should be made to the Indenture (as defined below).***

**General**

The Notes will be issued under a trust indenture dated October 9, 1996, as amended and supplemented from time to time (the "Indenture"), between the Corporation and CIBC Mellon Trust Company, as trustee (the "Trustee").

The Notes will be direct unsecured obligations of the Corporation and will not be secured by any mortgage, hypothec, pledge or other charge, except in circumstances as required by the Indenture. The Notes will rank equally and *pari passu*, except generally as to redemption and/or sinking fund provisions, with all other debentures, notes and other unsecured and unsubordinated indebtedness incurred by the Corporation, including its outstanding medium term notes and debentures, and will rank junior to First Mortgage Bonds issued under a trust deed and secured by a fixed and floating charge on the assets of the Corporation. There are currently no First Mortgage Bonds outstanding. The debentures of the Corporation issued under various trust indentures and the outstanding medium term notes of the Corporation have the benefit of a negative pledge subject to exceptions including the issue of First Mortgage Bonds.

A financial institution or institutions as appointed by the Corporation and designated in the pricing supplement or other prospectus supplement will act as the issuing agent, registrar and transfer agent and paying agent of the Notes.

The specific terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, dates of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), interest payment date(s), redemption provisions, if any, proceeds to the Corporation, the Agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth in a Pricing Supplement or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus.

**Term and Denomination**

The Notes will have maturities of not less than one year from the date of issue, will bear interest at a fixed or floating rate and will be issuable in fully registered form in denominations of $1,000 and integral multiples thereof with the minimum subscription being $5,000, or in each case the approximate equivalent amount thereof in a foreign currency.

**Fixed and Floating Rate Notes**

Notes may be issued as a fixed rate Note (a "Fixed Rate Note") or a floating rate Note (a "Floating Rate Note") or as a Note that is a Fixed Rate Note for a portion of its term and a Floating Rate Note for a portion of its term, all as specified in the applicable Pricing Supplement or other prospectus supplement.

Notes will bear interest from their date of issue or from the last interest payment date to which interest has been paid, whichever is later, provided that, in respect of the first interest payment after the issuance thereof, each Note will bear interest from the later of the date of such Note and the last interest payment date preceding the issuance of such Note. Interest on Fixed Rate Notes will be payable quarterly, semi-annually, annually or as otherwise specified in the applicable Pricing Supplement or other prospectus supplement, on the interest payment dates specified in the Notes and in the applicable Pricing Supplement or other prospectus supplement and at maturity. Interest on Floating Rate Notes will be payable on the interest reset dates specified in the Note and in the applicable Pricing Supplement or other prospectus supplement and at maturity.

Unless otherwise provided for in the applicable Pricing Supplement or other prospectus supplement, any interest on Notes will be determined on an actual/actual day count basis pursuant to which the actual number of days in the applicable interest period is divided by 365 (or, if any portion of the interest period falls in a leap year, the sum of (i) the actual number of days in that portion of the interest period falling within a leap year divided by 366 and (ii) the actual number of days in that portion of the interest period falling within a non-leap year divided by 365).

**Global Notes**

Unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement, all Notes denominated in Canadian or United States dollars will be represented in the form of fully registered global Notes (each, a "Global Note") held by, or on behalf of CDS Clearing and Depository Services Inc. or a successor (collectively, the "Depository"), as custodian of the Global Notes (for its participants as defined below) and registered in the name of the Depository or its nominee. Except as described below, no purchaser of a Note will be entitled to a certificate or other instrument from the Corporation or the Depository evidencing the purchaser's ownership of the Note. Instead, the Notes will

be represented only in book-entry form. Beneficial interests in the Global Notes, constituting ownership of the Notes, will be represented through book-entry accounts of institutions (including the Agents) acting on behalf of beneficial owners, as direct and indirect participants of the Depository ("participants"). Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Agent or Agents from whom the Note is purchased in accordance with the practices and procedures of the selling Agent or Agents. The practices of the Agents may vary but generally customer confirmations are issued promptly after execution of a customer order. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

Currently, the Depository only allows depository eligibility for securities denominated in Canadian or United States dollars. Any Notes denominated in a currency other than Canadian or United States dollars will be represented by Notes in definitive form ("Definitive Notes") until such time as the Depository allows depository eligibility for issues of securities denominated in such currencies.

If the Depository notifies the Corporation that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Corporation and the Trustee are unable to locate a qualified successor, or if an event of default has occurred and is continuing with respect to the Notes, or if the Corporation elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes. Beneficial owners of Notes represented by Global Notes may also receive Definitive Notes if the Trustee gives notice pursuant to the Indenture that an event of default has occurred and is continuing with respect to the Notes. In addition, if provided in the applicable Pricing Supplement or other prospectus supplement, Notes may be issued in the form of Definitive Notes.

*Payment of Interest and Principal*

The Depository or its nominee, as the registered owner of a Global Note, will be considered the sole owner of such Note for the purposes of receiving payments of interest and principal on the Note and for all other purposes under the Indenture and the Note.

The Corporation understands that the Depository or its nominee, upon receipt of any payment of interest or principal in respect of a Global Note, will credit participants' accounts on the date interest or principal is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or its nominee. The Corporation also understands that payments of interest and principal by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices. The responsibility and liability of the Corporation in respect of Notes represented by a Global Note is limited to making payment of any interest and principal due on such Global Note to the Depository or its nominee in the currency and in the manner described in the Global Note.

*Transfer of Notes*

Transfers of beneficial ownership of Notes represented by Global Notes will be effected through records maintained by the Depository or its nominee (with respect to interests of participants) and on the records of participants (with respect to interests of persons other than participants). Beneficial owners who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interest in Global Notes, may do so only through participants in the Depository's book entry system.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest in a Note represented by a Global Note (other than through a participant) may be limited due to the lack of a physical certificate.

The registered holder of a Definitive Note may transfer or exchange such Note upon payment of taxes incidental thereto, if any, by executing and delivering a form of transfer together with the Definitive Note to the applicable registrar and paying agent at its principal office in any of the cities of Vancouver, Calgary, Toronto, Montreal and Halifax whereupon a new Definitive Note will be issued in authorized denominations in the same aggregate principal amount as the Definitive Note so transferred, registered in the names of the transferees. No transfer of a Note will be registered during the ten business days (a business day for this purpose being a business day in the City of Toronto) immediately preceding any date fixed for payment of interest on such Note or five business days prior to the date of selection by the Trustee of any Notes to be redeemed.

**Redemption and Purchase of Notes**

Notes will not be redeemable by the Corporation or repayable at the option of the holder prior to maturity, unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement. The Corporation may at any time when not in default under the Indenture purchase Notes in the market (which shall include purchases from or through an investment dealer or a firm holding membership on a recognized stock exchange), or by tender, or by private contract, in accordance with the Indenture. Notes redeemed or purchased by the Corporation will be cancelled and may not be reissued.

**Negative Covenants**

In addition to certain other covenants in the Indenture, the Corporation covenants substantially to the effect that so long as any of the Notes are outstanding, it will not:

(a) except from time to time to secure First Mortgage Bonds, mortgage, pledge or charge or otherwise encumber any of its assets to secure any obligations unless at the same time it shall, in the opinion of counsel to the Corporation, secure equally and rateably with such obligations all of the Notes then outstanding by the same instrument or by other instrument in form and substance satisfactory to such counsel; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, (iii) security given in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, to secure any obligation repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such obligation is incurred provided such security is not given on fixed assets, or (iv) permitted encumbrances (as defined in the Indenture);

(b) permit any Restricted Subsidiary to create, incur or guarantee any indebtedness, except indebtedness to or of the Corporation or to a trustee in support of a guarantee of indebtedness of the Corporation; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, or (iii) indebtedness incurred in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such indebtedness is incurred, provided such security is not given on fixed assets;

(c) dispose of any indebtedness of a Restricted Subsidiary held by or for the Corporation;

(d) permit any Restricted Subsidiary to issue any shares if, as a result of such issue, such Restricted Subsidiary ceases to qualify as such; or

(e) create or issue any additional notes unless the Consolidated Net Earnings of the Corporation for any period of 12 consecutive calendar months of the 23 calendar months next preceding the date of application to the Trustee for certification of such additional notes, which shall have been selected by the Corporation, shall have been at least two times the annual interest requirements in respect of all Funded Obligations of the Corporation to be outstanding after the issue of such additional notes and after any retirements of Funded Obligations to be made out of the proceeds thereof or retirement whereof has been otherwise provided for and in respect of which proof has been afforded to the Trustee satisfactory to it that adequate provision has been made assuring that such Funded Obligations will be retired within 45 days after the issue of such additional notes; provided that the provisions of this covenant (e) shall not apply to the creation and issue of additional notes for the purpose of refunding any notes previously issued provided that (except in the case of refunding all of the notes) the aggregate principal amount of the additional notes does not exceed the aggregate principal amount of the notes to be refunded.

**Modification**

The rights of the holders of notes under the Indenture may be modified. For that purpose, among others, the Indenture contains provisions making binding upon all holders of notes, including all other medium term notes of the Corporation issued prior to the creation of the Trust Indenture, resolutions passed at meetings of such noteholders by the favourable votes of the holders of not less than 66 ⅔% of the principal amount of such notes voted on the resolution or instruments in writing signed by the holders of not less than 66 ⅔% of the principal amount of all such outstanding notes. In certain cases, modification will require separate assent by the holders of the required percentages of notes of each series or tranche outstanding under the Indenture or otherwise. Reference is made to the Indenture for detailed provisions relating to voting and meetings of noteholders.

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## CREDIT RATINGS

The Corporation's senior unsecured indebtedness currently has a rating of "A" by DBRS Limited ("DBRS") and "A-" by Standard & Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("S&P") (DBRS and S&P are each a "Rating Agency"). The rating outlook from DBRS is stable and the rating outlook from S&P is stable. These ratings are subject to change at any time at the sole discretion of the Ratings Agencies. We expect that at the date of issuance of any Notes, such Notes will be assigned the same ratings by these Rating Agencies. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The Rating Agencies' ratings for debt instruments range from a high of AAA to a low of D for DBRS and in the case of S&P, from a high of AAA to a low of D.

According to DBRS' rating system, debt securities rated A are characterized as "satisfactory credit quality" and this rating is the third highest of ten available rating categories. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have higher cyclical tendencies than higher rated securities. The assignment of a "high" or "low" designation within each rating category indicates relative standing within such category. The absence of a "high" or "low" designation indicates the rating is in the "middle" of the category. The "high", "middle" and "low" grades are not used for the AAA and D categories.

According to the S&P rating system, an obligation rated A- is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Notes are not recommendations to purchase, hold or sell the Notes. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely at any time by a Rating Agency in the future if, in its judgment, circumstances so warrant. The lowering of any rating of the Notes may negatively affect the quoted market price, if any, of the Notes. See "Risk Factors".

## EARNINGS COVERAGE RATIOS

The following earnings coverage ratios have been calculated on a consolidated basis for the respective 12 month periods ended December 31, 2009 and September 30, 2010 and are derived from audited financial information, in case of December 31, 2009, and unaudited financial information, in the case of September 30, 2010. The following earnings coverage ratios: (i) do not give effect to the issue of any Notes pursuant to this Prospectus; (ii) do not purport to be indicative of earnings coverage ratios for any future periods; and (iii) have been calculated based on Canadian GAAP. The following earnings coverage ratios give effect to the issuance of all of the Corporation's currently outstanding debt securities and assume repayment thereof as of the respective stated maturities of such debt securities.

| | **December 31, 2009** | **September 30, 2010** |
|---|---|---|
| Earnings coverage on long term debt | 2.5 times | 2.3 times |

## ELIGIBILITY FOR INVESTMENT

In the opinion of McCarthy Tétrault LLP, counsel to the Corporation, subject to the provisions of any particular registered plan or account, the Notes offered hereby, if issued on the date hereof, would be qualified investments under the Income Tax Act (Canada) (the "Tax Act") for trusts governed by registered retirement savings plans, registered retirement income funds, registered disability savings plans, registered education savings plans, deferred profit sharing plans (other than trusts governed by deferred profit sharing plans to which contributions are made by the Corporation or persons or partnerships with which the Corporation does not deal at arm's length for purposes of the Tax Act and tax-free savings accounts ("TFSAs"). Notwithstanding that the Notes may be a qualified investment for a trust governed by a TFSA, the holder of a TFSA that governs a trust which holds Notes will be subject to a penalty tax if the holder does not deal at arm's length with the Corporation for the purposes of the Tax Act or if the holder has a significant interest (within the meaning of the Tax Act) in the Corporation or a corporation, partnership or trust with which the Corporation does not deal at arm's length for the purposes of the Tax Act.

The Minister of Finance (Canada) has recently released proposed amendments to the Tax Act (the "Proposed TFSA Amendments") which will, if enacted, subject certain income of a TFSA to tax. The Proposed TFSA Amendments will

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subject any transfer of property occurring after October 16, 2009 (other than a transfer that is a distribution or a contribution) occurring between a holder's TFSA and the holder or a person who does not deal at arm's length, within the meaning of the Tax Act, with a holder (including, for example, another exempt plan of the holder) to a tax equal to 100% of the increase in the total fair market value of the property held in connection with the holder's TFSA that is attributable to the transfer. The Proposed TFSA Amendments will also subject any income (including capital gains) earned after October 16, 2009 that is reasonably attributed to a "prohibited investment" or a "deliberate over-contribution", each within the meaning of the Tax Act and the Proposed TFSA Amendments, to tax equal to 100% of the income or capital gain. No assurance can be given that the Proposed TFSA Amendments will be enacted in their current form, or at all. **Prospective purchasers who intend to hold Notes in their TFSAs should consult their own tax advisors regarding their particular circumstances.**

## LEGAL MATTERS

Certain legal matters in connection with the issuance of the Notes will be passed upon on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Fraser Milner Casgrain LLP. Each of the partners and associates of McCarthy Tétrault LLP as a group, and the partners and associates of Fraser Milner Casgrain LLP as a group, beneficially own, directly or indirectly, not more than 1% of the outstanding securities of each class of the Corporation.

## RISK FACTORS

In addition to the risk factors set forth below, additional risk factors are discussed in the AIF and in the Corporation's management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2009, which risk factors are incorporated herein by reference. Prospective purchasers of Notes should consider carefully the risk factors set forth below as well as other information contained in and incorporated by reference in this Prospectus, and in the applicable prospectus supplement before purchasing the Notes offered hereby.

### Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Notes are not a recommendation to purchase, hold or sell the Notes, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time or that these ratings will not be revised or withdrawn entirely in the future by the relevant rating agency. Real or anticipated changes in credit ratings on the Notes may affect the market value of the Notes. In addition, real or anticipated changes in credit ratings can affect the cost at which the Corporation can access the debt market.

### Lack of Public Market for the Notes

This Prospectus qualifies new issues of Notes for which there is no existing trading market. The Corporation does not intend to list the Notes on any securities exchange or to arrange for any quotation system to quote the Notes. There can be no assurance as to the liquidity of any trading market for the Notes or that a trading market for any of the Notes will develop. Even if a trading market develops for the Notes, those Notes could trade at prices that may be higher or lower than their initial offering prices. The market price for the Notes may be affected by prevailing interest rates, the Corporation's results of operations and financial position, the ratings assigned to the Notes or the Corporation, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Corporation.

## PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus, the accompanying Pricing Supplement or other prospectus supplement relating to the securities purchased by a purchaser and any amendment thereto. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus, the accompanying Pricing Supplement or other prospectus supplement relating to the securities purchased by a purchaser and any amendment thereto contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province of residence. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province of residence for the particulars of these rights or consult with a legal adviser.

**CERTIFICATE OF ENBRIDGE GAS DISTRIBUTION INC.**

Dated: November 16, 2010

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

Janet A. Holder
*"Janet A Holder"*

President
(as Chief Executive Officer)

Narinder K. Kishinchandani
*"Narinder K. Kishinchandani"*

Vice President, Finance
(as Chief Financial Officer)

On behalf of the Board of Directors

J. Lorne Braithwaite
*"J. Lorne Braithwaite"*

Director

David A Leslie
*"David A Leslie"*

Director

## CERTIFICATE OF THE AGENTS

Dated: November 16, 2010

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

| | | |
|---|---|---|
| **RBC Dominion Securities Inc.** | **BMO Nesbitt Burns Inc.** | **CIBC World Markets Inc.** |
| *"Tushar Kittur"*<br>Tushar Kittur | *"Aaron M. Engen"*<br>Aaron M. Engen | *"Sean Gilbert"*<br>Sean Gilbert |
| **Desjardins Securities Inc.** | **HSBC Securities (Canada) Inc.** | **Merrill Lynch Canada Inc.** |
| *"Ryan Godfrey"*<br>Ryan Godfrey | *"Rod A. McIssac"*<br>Rod A. McIssac | *"Timothy W. Watson"*<br>Timothy W. Watson |
| **National Bank Financial Inc.** | **Scotia Capital Inc.** | **TD Securities Inc.** |
| *"Iain Watson"*<br>Iain Watson | *"Murray W. Neal"*<br>Murray W. Neal | *"Alec W.G. Clark"*<br>Alec W.G. Clark |

**SCHEDULE A**
**DEFINITIONS**

The following terms which are used above are defined in the Indenture substantially as follows:

"***additional notes***" means all Funded Obligations of the Corporation other than First Mortgage Bonds and the previously issued medium term notes and debentures of the Corporation.

"***Attributable Debt***" means, as to any particular lease under which any person is at the time liable and at any date as of which the amount thereof is to be determined, the lesser of (i) the fair market value of the property (as determined by the directors) subject to such lease, and (ii) the total net amount of rent required to be paid by such person under such lease during the remaining term thereof (including any period for which such lease has been extended), discounted from the respective due dates thereof to such date at a rate of interest per annum equal to the weighted average interest rate of all unsecured and unsubordinated indebtedness of the Corporation. The net amount of rent required to be paid under any such lease for any such period shall be the aggregate amount of the rent payable by the lessee with respect to such period after excluding amounts required to be paid on account of maintenance and repairs, insurance, taxes, assessment, water rates and similar charges. In the case of any lease which is terminable by the lessee upon payment of a penalty, such net amount shall also include the amount of such penalty, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated.

"***Consolidated Net Earnings***" for any specified period of 12 months means the net earnings of the Corporation on a consolidated basis for such period (excluding gains or losses on the disposal of investments or fixed assets in each case in excess of $50,000 in the aggregate and other non recurring items in excess of $50,000 in the aggregate) before deductions for income taxes, interest on Funded Obligations of the Corporation, dividends on preferred shares of the Corporation which have been deducted to calculate net earnings, amortization of debt premium, discount and expense and the cost, whether or not amortized, of conversion of facilities and appliances of the Corporation and its customers to the use of natural gas, all as determined in accordance with generally accepted accounting principles and reported on by the Corporation's auditors without, in their opinion, material adverse qualification; provided that if, within or after the period for which Consolidated Net Earnings is being determined but at or prior to the issuance of the additional notes in respect of which such determination is being made, the Corporation or any company, a portion of the net earnings (losses) of which are included in determining Consolidated Net Earnings acquires (a) any assets, or (b) an interest in any other company which would thereafter permit the inclusion in Consolidated Net Earnings of the Corporation's equity in the net earnings (losses) of such other company, then Consolidated Net Earnings may be determined as if such assets or interest had been acquired prior to and owned throughout such period if net earnings (losses) from such assets or interest can be determined or estimated for such period in accordance with generally accepted accounting principles.

"***Consolidated Net Tangible Assets***" means, on any date, the aggregate amount of assets after deducting therefrom (i) all current liabilities, and (ii) all goodwill, trade names, trade marks, patents, organization expenses and other like intangibles of the Corporation and its consolidated subsidiaries, all as set forth on the most recent balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

"***Excluded Sale and Leaseback***" means any Sale and Leaseback in respect of which:

(a) the lease is for a period, including renewal rights, of not in excess of three years, or

(b) an amount equal to the greater of the net proceeds of the sale of the property leased pursuant to such arrangement and the fair market value of such property (as determined by the directors) is applied within 180 days after the sale has been completed to:

  (i) the retirement, otherwise than by payment at maturity or pursuant to any mandatory sinking fund payment or any mandatory prepayment provision, of Funded Obligations of the Corporation or a Restricted Subsidiary, or

  (ii) the purchase of other property having a fair market value (as determined by the directors) at least equal to the fair market value (as so determined) of the property leased in such Sale and Leaseback, or

(c) such Sale and Leaseback is entered into prior to, at the time of, or within 180 days after the acquisition of the property which is subject thereto, or

(d) the only parties are the Corporation and Restricted Subsidiaries.

"***First Mortgage Bonds***" means all first mortgage bonds or other first mortgage obligations of the Corporation, whether heretofore or hereafter issued, secured by a first fixed and specific charge on substantially all the fixed assets of the Corporation (whether or not also secured by floating charge or by any other security) and includes, without limitation, the first mortgage bonds of the Corporation outstanding from time to time under a Deed of Trust and Mortgage dated as of November 1, 1954 (and deeds supplemental thereto) made by the Corporation and The Toronto General Trusts Corporation (succeeded by Montreal Trust Company of Canada), as trustee.

"***Funded Obligations***" means any indebtedness, whether by way of bonds, debentures, debenture stock, notes or otherwise, whether secured or unsecured, the due date of payment of which, including any right of extension or renewal, is 18 months or more after the date of issue or incurring thereof but does not include Purchase Money Obligations or Permitted Prior Charges.

"***Permitted Prior Charges***" means Sale and Leasebacks and security for obligations, except First Mortgage Bonds, of the Corporation or any of its Restricted Subsidiaries, provided that the aggregate amount of the Attributable Debt of the Corporation and its Restricted Subsidiaries of all Sale and Leasebacks, excepting Excluded Sale and Leasebacks, and all obligations of the Corporation and its Restricted Subsidiaries so secured does not exceed the greater of 5% of Consolidated Net Tangible Assets of the Corporation and 10% of Shareholders' Equity of the Corporation.

"***Purchase Money Obligations***" means any mortgages, hypothecs, charges, vendors' privileges, vendors' liens, or other encumbrances upon property (and the indebtedness represented thereby) given or assumed or arising by operation of law, to provide or secure the whole or any part of the consideration for the acquisition of such property and includes renewals, refundings and extensions not in excess of the principal amount thereof immediately prior to such renewal, refunding or extension.

"***Restricted Subsidiary***" means any corporation, company or organization, more than 50% of the outstanding shares of each class of the capital stock of which having attached to them voting rights under all circumstances are owned by the Corporation and/or one or more Restricted Subsidiary, provided the Corporation shall have, by resolution of its directors, designated such corporation, company or organization as a Restricted Subsidiary and more than 50% of the outstanding shares of each such class of the capital stock thereof are still owned by the Corporation and/or one or more Restricted Subsidiary.

"***Sale and Leaseback***" means any transaction with any bank, insurance company or other lender or investor, or to which any such bank, insurance company, lender or investor is a party, providing for the leasing by the Corporation or a Restricted Subsidiary of any property, real or personal, moveable or immovable, which has been or is to be sold or transferred by the Corporation or such Restricted Subsidiary to such bank, insurance company, lender or investor in contemplation of such leasing.

"***Shareholders' Equity***" means, on any date, the total amount of shareholders' equity of the Corporation and its consolidated subsidiaries including future income tax liabilities, all as set forth in the most recent consolidated balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

**SCHEDULE B**
**AUDITORS' CONSENT**

We have read the short form base shelf prospectus of Enbridge Gas Distribution Inc. (the "Corporation") dated November 16, 2010 relating to the qualification for distribution by the Corporation of up to $800 million Medium Term Notes (unsecured). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use, through incorporation by reference, in the above-mentioned prospectus of our report to the shareholders of the Corporation on the consolidated statements of financial position of the Corporation as at December 31, 2009 and 2008 and on the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years ended December 31, 2009 and December 31, 2008. Our report is dated February 18, 2010.

(signed) *"PricewaterhouseCoopers LLP"*

Chartered Accountants, Licensed Public Accountants
Toronto, Ontario, Canada
November 16, 2010