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Labour Forecast
2009-2010

May 2009

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0. BACKGROUND

This report contains detailed information concerning the method used by Newfoundland Power to forecast its test year FTEs and labour expense. In addition, it explains the assumptions used to determine forecast vacancies.[1]

Newfoundland Power's current labour requirements will tend to be consistent from year to year.[2] This reflects a consistency in the work to be executed by the Company from year to year. Work requirements are reflected in workforce decisions, such as the hiring of new employees or the replacement of retiring workers.

The method used to forecast labour requirements and FTEs for a test year reflects this basic workforce management philosophy.

2.0 FORECASTING WORKFORCE REQUIREMENTS

Forecasting the Work

The starting point in forecasting Newfoundland Power's annual labour requirements is the Company's annual capital and operational work requirements.[3]

Annual capital work requirements are principally based on specific expenditures required to replace deteriorated, defective or obsolete equipment, and to serve forecast customer and sales growth[4].

Annual operating work requirements are principally focused on the maintenance and operation of the electrical system, response to customer inquiries, and commercial functions such as meter reading and billing.[5] These requirements tend to be stable over time. For this reason, historical expenditure, adjusted for changes in operating requirements, is the foundation for forecasting annual operating work requirements.

[1] In Order No. P. U. 32 (2007), the Board directed Newfoundland Power to include this information as part of its next general rate application.

[2] For the period from 1993 through 2005, Newfoundland Power's workforce declined significantly as a result of a series of 6 early retirement programs. Current workforce levels are considered to be broadly consistent with least cost customer service delivery over the long term.

[3] In addition to capital and operating requirements, there are labour requirements for rechargeable and recoverable items. These include labour associated with material handling (i.e., stores) and vehicle service centre labour costs, which are recharged as overheads on operating and capital work. It also includes customer jobbing, third party provisioning services and inter-affiliate labour charges.

[4] These requirements are approved by the Board on a prospective basis each year through the Company's capital budget applications.

[5] Annual operating work requirements also include general support functions, such as information services, human resources and finance.

Workforce Options

Having determined the annual work requirements, the Company considers the human resources that will be deployed to meet these requirements.

The Company's annual work requirements are met using a combination of regular employees, temporary employees and contractors. This approach permits Newfoundland Power to maintain a highly skilled core workforce and maintain reasonable flexibility to respond to variations in work requirements on a least cost basis.

Annual capital work requirements tend to be met by a combination of the Company's internal workforce and contractors. This is partly attributable to the variable nature of these work requirements.[6] It is also consistent with the deployment of the Company's internal workforce. [7]

Annual operating work requirements tend to be met by the Company's internal workforce.[8] This is partly attributable to stability of these work requirements on a year over year basis. It is also partly attributable to the specialized nature of these work requirements.[9]

Vacancy Assumptions

In determining the internal workforce available to execute the annual capital and operating work requirements, the Company assesses its internal workforce on a full-time equivalent (FTE) basis.[10]

The actual FTEs for the most recently completed year reflect the impact of all vacancies in that year. In other words, the FTEs for the most recent completed year includes only the actual paid hours *worked in that year*. For this reason, the FTEs for the most recent completed year are the basis Newfoundland Power uses for forecasting FTEs.

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[6] The specific requirements of annual capital work have different labour requirements depending on the projects involved. For example, penstock construction requires riggers and welders. However, electrical system operations have no ongoing requirement for those skilled trades. Accordingly, such work would be performed by contractors.

[7] Deployment of Powerline Technicians is an example of this. Powerline Technicians perform a mixture of operating and capital maintenance. In winter, Newfoundland Power's service obligations practically require it to have Powerline Technicians deployed across its service territory in sufficient numbers to respond to seasonal electrical system trouble. In the construction season, Powerline Technicians can be deployed to construction sites across the province as necessary.

[8] Approximately 10% of Newfoundland Power's internal workforce is temporary labour. Use of temporary labour provides operating flexibility.

[9] Specialized knowledge of electrical system operations is required for a great deal of operational work and is a core competency of Newfoundland Power's workforce. This specialized knowledge is typically not required to perform much of the capital work requirements of the Company.

[10] Newfoundland Power calculates FTEs based on employee hours worked divided by total working hours in a year. For approximately 50% of the workforce, the total working hours in a year are 2,080. For the remainder, the total working hours in a year are 1,950. The FTE calculation reflects only hours worked and permits a better matching of work requirements to available workforce options than forecasting positions and applying a vacancy allowance.

In forecasting FTEs, Newfoundland Power will make adjustments for future years. This is done to better predict availability of the internal workforce to meet work requirements. This, in turn, permits the Company to assess its workforce options. [11]

The typical adjustments to an FTE forecast include anticipated retirements, leaves of absence[12], terminations and new hires. These adjustments reflect the timing and salary impacts of workforce changes. For example, in the case of retirements, differences in salary, and timing gaps or overlaps among employees entering and leaving the workforce, can be incorporated into the adjustments.[13] A similar approach is used for employees commencing leaves of absence and those returning from leave.

These adjustments are fully reflected in both forecast FTEs and labour costs. The forecast FTEs are a tool to assess the *internal* workforce available to meet overall work requirements. The forecast labour costs reflect salary and timing differences associated with changes in the internal workforce.

Newfoundland Power's assessment of its internal workforce is undertaken in the context of its total forecast labour requirements. These total labour requirements are a function of forecast capital and operating work requirements.[14]

Reconciling Work and Labour

Newfoundland Power's total forecast labour requirements for 2009 are approximately $60.2 million. For the 2010 test year, the total forecast labour requirements are $62.3 million. These requirements reflect forecast capital and operational work requirements for each year.

The Company's forecast internal labour expense for 2009 is $52.2 million. For 2010, forecast internal labour expense is $54.9 million. The difference between the total forecast labour requirement and the Company's internal labour available will be addressed using contract labour.

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11 From a practical perspective, forecast FTEs will become the basis for the Company's determination of hiring requirements and contract labour requirements.

12 Leaves of absence include maternity leave, absences due to long-term disability or workplace injury, education leave and other leaves of absence approved by the Company.

13 The time period between employees entering and leaving the workforce can be either negative or positive. For example if a replacement employee arrives before a senior employee retires to avail of a training opportunity, then this will increase the FTE count and labour expense. However, if there is a period of time a position remains vacant awaiting a replacement employee to enter the workforce, then this will decrease the FTE count and labour expense.

14 The loss of an employee in any year will typically result in the work being performed by temporary labour or a contractor. It is unusual that either capital or operating work would not be performed in any given year due to the loss of an employee.

3.0 2009 AND 2010 LABOUR FORECASTS

2009 FTEs and Internal Labour Expense

The 2009 FTEs and internal labour expense were calculated using the 2008 year end FTEs and labour expense as the starting point. In 2008, the year-end FTEs, based on the *actual hours worked,* was 628.2. The associated internal labour expense was $49.4 million.

To account for the impact of inflation in developing the 2009 forecast, the 2008 internal labour expense is adjusted to reflect salary increases applicable to the current year.

Further adjustments are then made to the FTE forecast to reflect factors that are expected to influence internal labour in the current year. For example, the 2009 forecast reflects 5 projected retirements and 15 new hires. The new hires will meet increased requirements for Apprentice Powerline Technicians, and Engineering Technicians, as well as new staff to support the Company's conservation initiatives. In addition, the 2009 FTEs and internal labour expense is increased to reflect new employees who worked a partial year in 2008, but are anticipated to be in the workforce for a full year in 2009.

Schedule A presents the detailed breakdown of forecast internal labour expense and FTEs for 2009.

2010 FTEs and Internal Labour Expense

The 2010 FTEs and internal labour expense were calculated using the 2009 forecast as the starting point. To account for the impact of inflation, the 2009 internal labour expense is adjusted to reflect salary increases applicable to 2010.

The test year labour forecast reflects 12 projected retirements and 6 new hires. The new hires will meet increased requirements for Powerline Technician Apprentices and an Electrical Maintenance Apprentice. In addition, the 2010 FTEs and internal labour expense has increased for new employees working a partial year in 2009 who are anticipated to be in the workforce for a full year in 2010.

Schedule B presents the detailed breakdown of forecast internal labour expense and FTEs for 2010.

Schedule A
2009 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2008 Workforce			
Operating	26,739		1
Capital	18,685		
Rechargeable & Recoverable	3,994		
Total	**49,418**	**628.2**	2
2009 Salary Increase	**2,273**		3
Adjustments for 2009			
2009 Retirements			
Employee Retirement[15]	(163)	(1.7)	4
Retirement Replacement	109	1.5	5
2009 Leaves of Absence			
Employees Taking Leaves	(250)	(3.4)	6
Employees Returning from Leaves	280	3.3	7
Terminations	(125)	(0.9)	8
New Hires	514	8.4	9
Partial Year Adjustments[16]	184	5.1	10
Apprentice Top-up	19		11
2009 Adjusted Workforce	**52,259**	**640.5**	12
2009 Forecast Workforce			
Operating	27,965		13
Capital	20,116		
Rechargeable & Recoverable	4,178		
Total	**52,259**		14

15 Retirement estimates are based upon employees reaching age 65, or have reached age 60 with the combination of 95 years of age plus service, or have expressed interest in retiring prior to reaching this milestone.

16 Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2008. These employees would not have accounted for a full annual salary in the 2008 labour expense, nor would they have accounted for a full FTE in 2008.

Notes for Schedule A

No.	Description
1	The actual year end operating labour cost for 2008. It includes the impact of all retirements, leaves of absence, terminations and new hires experienced in 2008.
2	The 2008 actual year end FTEs count is reflective of the 2008 work requirement. It reflects the impacts, including timing impacts, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees experienced in 2008. Total labour expense includes overhead loading for vehicle expenses.
3	The 2009 salary increase is based upon a weighted average salary increase of 4.6%.
4	In 2009, there are 5 employees who are expected to retire. The 2009 labour reduction for retirement is \$163,000. Due to the timing of the estimated retirements, the 2009 reduction in FTEs is 1.7.
5	Only 3 of the 5 retiring employees will be replaced in 2009. A 4th employee will be retiring at year end and will not be replaced until 2010. A combination of lower salary and the timing of replacement hires, results in \$109,000 labour cost and only 1.5 FTE increase for 2009.
6	In 2009, the Company forecasts 11 leaves of absence, consisting of 2 maternity leaves, 6 long-term disability absences and 3 injured workers on workplace compensation. The 2009 labour reduction for leaves is \$250,000, with a corresponding FTE reduction of 3.4.
7	In 2009, the Company forecasts 7 employees returning from various forms of leave. These include 2 employees on maternity leave, 3 on long-term disability and 2 on workplace compensation. The 2009 labour increase for leaves is \$280,000, with a corresponding FTE increase of 3.3.
8	In 2009, the Company forecasts 1 employee terminating their employment at mid-year. Also, of the 4 employees who died in 2008, one will not be replaced in 2009. This employee's 2008 salary has been removed from the 2009 forecast, and the FTE count has been adjusted accordingly. A second deceased employee was replaced in 2008, with a 40 workday lag in hiring. Accordingly, a 40 day increase in salary and FTE count was added to 2009. The remaining 2 deceased employees require no adjustment for 2009, as their replacements will work an equivalent period in 2009 as worked in 2008 by the employees they replaced. The 2009 labour reduction for terminations is \$125,000, with a corresponding FTE reduction of 0.9.
9	In 2009, the Company forecasts 15 new hires. These consist of 6 employees to carry out the 5-year CDM plan, 6 new Block 1 Powerline Technician Apprentices, 1 Planner and 2 temporary Engineering Technicians. These new hires do not include replacement employees associated with retirements. The 2009 labour increase for new hires is \$514,000, with a corresponding FTE increase of 8.4.
10	The 2009 labour increase for partial year adjustments is \$184,000, with a corresponding FTE increase of 5.1.
11	Represents the training allowance top up to 100% of salary, during the eight week period when Power Line Technician Apprentices return to school.
12	The 2009 forecast FTE count.
13	The 2009 forecast operating labour cost.
14	Total labour expense includes overhead loading for vehicle expenses.

Schedule B
2010 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2009 Forecast Workforce			
Operating	27,965		1
Capital	20,116		
Rechargeable & Recoverable	4,178		
Total	**52,259**	**640.5**	2
2010 Salary Increase	**2,090**		3
Adjustments for 2010			
2010 Retirements			
Employee Retirement[17]	(322)	(3.0)	4
Retirement Replacement	208	2.5	5
2010 Leaves of Absence			
Employees Taking Leaves	(176)	(2.4)	6
Employees Returning from Leaves	226	3.0	7
Terminations	(132)	(1.5)	8
New Hires	232	3.8	9
Partial Year Adjustments[18]	536	7.8	10
Apprentice Top-up	16		11
2010 Adjusted Workforce	**54,937**	**650.7**	12
2010 Forecast Workforce			
Operating	29,109		13
Capital	21,383		
Rechargeable & Recoverable	4,445		
Total	**54,937**		14

[17] Retirement estimates are based upon employees reaching age 65, or have reached age 60 with the combination of 95 years of age plus service.

[18] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2009. These employees would not have accounted for a full annual salary in the 2009 labour expense, nor would they have accounted for a full FTE in 2009.

Notes for Schedule B

No.	Description
1	The forecast operating labour cost for 2009. It includes the impact of all retirements, leaves of absence, terminations and new hires anticipated for 2009, and reflected in the adjustments set out in Schedule A.
2	The 2009 forecast FTEs are reflective of the forecast 2009 work requirement. It reflects the detailed impact, including timing, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees anticipated in 2009, and reflected in Schedule A. Total labour expense includes overhead loading for vehicle expenses.
3	The 2010 salary increase is based upon a weighted average salary increase of 4.0%
4	In 2010, there are 12 employees eligible to retire. The 2010 labour reduction for retirement is $322,000. The 2010 reduction in FTEs of 3.0 reflects the timing of the forecast retirements.
5	Only 6 of the 12 retiring employees will be replaced in 2010. The remaining 6 employees are forecast to retire at year-end, and will not be replaced in 2010. Only 3 of the 6 employees retiring at year-end 2010 will be replaced in 2011. A combination of lower salary and the timing of replacement hires, results in $208,000 labour cost and only 2.5 FTE increase for 2010.
6	In 2010, the Company forecasts 4 employees taking leaves of absence based upon recent experience. The 2010 labour reduction for leaves is $176,000, with a corresponding FTE reduction of 2.4.
7	In 2010, the Company forecasts 7 employees returning from various forms of leave. These include 1 employee on maternity leave, 3 on long-term disability and 3 on workplace compensation. The 2010 labour increase for leaves is $226,000, with a corresponding FTE increase of 3.0.
8	In 2010, the Company forecasts 3 employees terminating their employment at mid-year based upon recent experience. The 2010 labour reduction for terminations is $132,000, and a corresponding FTE reduction of 1.5.
9	In 2010, the Company forecasts 6 new hires. These consist of 5 new Block 1 Powerline Technician Apprentices and 1 Electrical Maintenance Apprentice. These new hires do not include replacement employees associated with retirements. The 2010 labour increase for new hires is $160,000, with a corresponding FTE increase of 3.0.
10	The 2010 labour increase for partial year adjustments is $536,000, with a corresponding FTE increase of 7.8.
11	Represents the training allowance top up to 100% of salary, during the eight week period when Power Line Technician Apprentices return to school.
12	The 2010 forecast FTE count.
13	The 2010 forecast operating labour cost.
14	Total labour expense includes overhead loading for vehicle expenses.

2010 Rate Base Allowances

May 2009

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1.0 INTRODUCTION

It is mainstream practice for a utility's rate base to include allowances for (i) funds used during construction ("AFUDC"), (ii) cash working capital ("CWC Allowance"), and (iii) materials and supplies ("Materials Allowance").[1]

For this Application, Newfoundland Power has reviewed its CWC Allowance and Materials Allowance to reflect any changes that have occurred since the last detailed reviews.[2]

The CWC Allowance calculated for 2010 is $9,266,000. This is 2.0% of forecast 2010 regulated cash operating expenses.[3]

The Materials Allowance calculated for 2010 is $4,453,000. This reflects a revised expansion factor for the calculation of expansion inventory of 20.2%.[4]

2.0 CWC ALLOWANCE

2.1 Methodology

Mainstream regulatory practice of Canadian utilities, including Newfoundland and Labrador Hydro ("Hydro"), is to use a lead/lag study to calculate the CWC Allowance.[5]

A lead/lag study recognizes that the utility renders service to customers prior to the receipt of payment for the service from customers. It also recognizes that there is generally a delay in payment by the utility for the goods and services it acquires.

A lead/lag study analyzes transactions over a period of time to determine (i) for each revenue stream, the average number of lag days between the provision of service to customers and the receipt of payment for that service from customers (the revenue lags), and (ii) for each expense, the average number of lag days between the provision of service to customers and the date that the utility pays for the goods and services that it acquires to provide service (the expense lags). The difference between these two lags is referred to as a net lag or net lead.

A net lag occurs when the payment of an expense precedes the collection of its related revenue stream. In this situation, the utility's investors must supply capital to finance the expense until receipt of the related revenues. A net lead position occurs in the opposite situation with the opposite impact.

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1 Hydro's rate base includes these 3 allowances in addition to a fuel inventory allowance.

2 AFUDC, which reflects financing costs of work in progress, is calculated using the Company's weighted average cost of capital. Accordingly, no further review of AFUDC for 2010 is required. In 2010, forecast AFUDC is $405,000.

3 This compares to 2.1% of forecast regulated cash operating expenses used for 2008.

4 This compares with an expansion factor of 19.4% used in 2008.

5 Of the 26 Canadian utilities surveyed in 2007, all follow the Asset Rate Base Method, and 21 used a lead/lag study to calculate their CWC Allowance.

Once the revenue lags and expense lags are determined, the calculation of the CWC Allowance involves the following steps:

1. Weight each revenue lag by its related revenue stream to calculate the total weighted average revenue lag.
2. Weight each expense lag by its related expense to calculate the total weighted average expense lag.
3. Subtract the weighted average expense lag from the weighted average revenue lag and divide the result by 365 days. This is the CWC factor.[6]
4. Multiply the CWC factor by the total regulated expenses to calculate the average amount of working capital required to finance the expenses.
5. Add to the amount determined in step 4 the net impact of the collection and payment of the harmonized sales tax ("HST") on working capital. The result is the CWC Allowance.

The CWC Allowance determined via a lead/lag study is indicative of a utility's average daily working capital requirements.

2.2 2010 Leads & Lags

General

In determining its 2010 forecast cash working capital allowance, each of the individual revenue and expense lags were reviewed and updated to reflect any observed changes in revenue/expense streams. In addition, the timing and remittance of HST payments were also reviewed and updated.

Newfoundland Power's lead/lag study is based on 2008 actual data as it represents the most recent historical results available at the time. There have been no material changes to the Company's billing and collection procedures or to its payment procedures since 2008. In addition, there are no material changes forecast for the 2010 Test Year.

Through the lead/lag study, Newfoundland Power has determined (i) its revenue lags, (ii) its expense lags and (iii) the leads/lags associated with HST for 2010 Test Year. Together, these leads and lags form the basis for the 2010 CWC Allowance.

The leads and lags calculated have been applied to the Company's forecast 2010 test year data to calculate the proposed 2010 CWC Allowance. These calculations are summarized below.

Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2008 to determine the average number of lag days between when service is provided to customers and when payment for the service is received from customers.

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[6] In a net lag situation, the CWC factor represents the percentage of expenses that has to be financed by the utility's investors during the year. Investor funding is necessitated by the fact that the cash outflows for expenses preceded the cash inflows for the related revenues. The CWC Allowance for a net lag is added to the rate base in order to provide a utility with a reasonable opportunity to recover the cost of the related investor supplied funding. In a net lead situation, the opposite is true.

Newfoundland Power has two distinct revenue streams which can broadly be described as "consumer billings" and "other billings".

Consumer billings included in the calculation of the CWC Allowance are composed of (i) electricity billings and related municipal tax billings, (ii) forfeited discounts and interest earned on overdue accounts receivable, (iii) ancillary items such as connection/reconnection fees, and (iv) HST.

Other billings are composed primarily of pole rentals, and include various miscellaneous revenues and HST.

A separate revenue lag was calculated for consumer billings and other billings.

The calculated revenue lags for consumer billings and other billings were weighted, based on the percentage of the total 2010 forecast billings represented by each, to produce a total weighted average 2010 revenue lag for the Company of 37.55 days.[7] This is set out in Schedule 1 of Appendix A.

Expense Lag
The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2008 to determine the average number of lag days between when service is provided to customers and when payment is made for the goods and services that are acquired to provide service.

The calculated expense lag of each cash operating expense was weighted based on the percentage of the total 2010 forecast cash operating expenses represented by each to produce a total weighted average 2010 expense lag for the Company of 30.28 days.[8] This is set out in Schedule 2 of Appendix A.

HST Adjustment
HST is collected from customers on certain billed revenues and paid to suppliers on certain expenses and capitalized costs. The difference between HST collections and HST payments in each month is settled with government on the last day of the month that follows the month in which the HST was billed or, if that day is not a business day, on the first business day thereafter.

On average, HST on most of Newfoundland Power's billings is collected from customers before it is settled with government. The Company has use of these funds between the collection date and the settlement date. This serves to reduce the necessary CWC Allowance.

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7 In comparison, the revenue lag included in the 2008 test year cash working capital study was 39.34 days. The reduction in the revenue lag days from 39.34 to 37.55 days indicates that the number of lag days between the provision of service to customers and the receipt of payment for that service from customers has decreased since the 2008 lead/lag study.

8 In comparison, the expense lag included in the 2008 test year cash working capital study was 31.61 days. The reduction in the expense lag days from 31.61 to 30.28 days indicates that the number of lag days between the provision of service to Newfoundland Power and the payment for that service has decreased since the 2008 lead/lag study.

On average, HST billed by Newfoundland Power's suppliers is paid to those suppliers before it is settled with government. The Company has to finance the HST between the payment date and the settlement date. This serves to increase the necessary CWC Allowance.

Newfoundland Power's 2008 HST adjustment is set out in Schedule 3 of Appendix A. The net HST impact is a $436,000 increase in the Company's proposed 2010 test year CWC Allowance. This is reduced from the 2008 Test Year HST adjustment of $780,000 primarily due to a reduction in the HST rate from 14% to 13% and an increase in the lead associated with HST on customer billings.

2.3 2010 Test Year CWC Allowance

Newfoundland Power's proposed 2010 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $9,266,000. This is set out in Schedule 4 of Appendix A.[9]

The effect of the proposed 2010 CWC Allowance is to provide Newfoundland Power with a reasonable opportunity to recover its cost of providing regulated service.

3.0 MATERIALS & SUPPLIES ALLOWANCE

The inclusion of a Materials Allowance in rate base is an accepted practice for regulated utilities. The Materials Allowance provides regulated utilities with a means to reasonably recover the cost of financing inventories. In determining the amounts of materials and supplies to include in rate base, Newfoundland Power is required to exclude that portion that it identifies as expansion inventory.[10]

In Order No. P.U. 32 (2007), the Board approved rate base calculations of Newfoundland Power's rate base including a Materials Allowance based upon (i) a thirteen month average versus a simple average and (ii) expansion inventory of 19.4%.[11]

For the 2010 general rate application, Newfoundland Power has revised its expansion factor used in the calculation of the Materials Allowance based on a review of actual inventories in 2008 used for expansion projects. The revised expansion factor for the 2010 test year is 20.2% versus 19.4% calculated for the 2008 test year. The increase in the expansion factor effectively reduces the 2010 rate base and associated revenue requirements.

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[9] For comparative purposes, the cash working capital allowance included in the 2008 test year was $9.7 million.

[10] In Order No. P.U. 1 (1974), Newfoundland Power was directed by the Board to identify and exclude from rate base all inventories and supplies related to expansion of the electrical system. Essentially, the Board noted that materials and supplies related to future expansion were similar in nature to work in progress in that they are held to provide future service. Similar to the treatment of work in progress, materials and supplies should be excluded in the calculation of rate base.

[11] Newfoundland Power's average rate base for the 2008 test year was approved by the Board in Order No. P.U. 32 (2007) and included the Company's revised calculation of its materials and supplies allowance.

Newfoundland Power Inc.

2010 Forecast Revenue Lag

Cash Inflows	2010 Forecast [1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
Consumer Billings	563,695	98.16%	36.34	35.67
Other Billings	10,583	1.84%	102.31	1.88
Total	574,278	100.00%		**37.55**

[1] Reconciliation to Revenue Requirement ($000s) :

Total Billings Above	574,278
Rate Stabilization Adjustments	(3,519)
Municipal Tax Billings	(13,346)
Billings Recorded as Revenue	557,413
Revenue excluded from CWC Allowance	
Amortization of 2005 Unbilled Revenue	4,618
Amortization of Municipal Tax Liability	1,362
Interest Income	100
Interest on Customer Finance Program Receivables	250
Total Revenue	563,743
Interest on Rate Stabilization Account	(141)
Other Adjustments (See Exhibit 7, Line 18)	(88)
2010 Revenue Requirement	563,514

Newfoundland Power Inc.

2010 Forecast Expense Lag

		2010 Forcast	Adjustments[1]	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
			($000s)				
	Operating Expenses						
1	Labour	31,173		31,173	7.06%	43.21	3.05
2	Vehicle Expenses	1,492		1,492	0.34%	45.21	0.15
3	Operating Materials	1,082		1,082	0.25%	45.21	0.11
4	Inter-Company Charges	910		910	0.21%	45.21	0.09
5	Plants,Subs,System Ops & Buildings	1,952		1,952	0.44%	45.21	0.20
6	Travel	1,160		1,160	0.26%	45.21	0.12
7	Tools and Clothing Allowance	1,108		1,108	0.25%	45.21	0.11
8	Miscellaneous	1,547		1,547	0.36%	45.21	0.16
9	Bank Service Charges & PUB Assessment	750		750	0.17%	(21.21)	(0.04)
10	Uncollectible Bills	963	963	0			
11	Insurance	1,100		1,100	0.25%	(167.50)	(0.42)
12	Pension & ERP Expense	5,701	257	5,444	1.23%	37.08	0.46
13	Retirement Allowances	325	325	0			
14	Education and Training	270		270	0.06%	45.21	0.03
15	Trustee & Directors' Fees	394		394	0.09%	36.45	0.03
16	Other Company Fees[2]	3,815	578	3,237	0.73%	45.21	0.33
17	Stationery & Copying	337		337	0.08%	45.21	0.03
18	Equipment Rental & Maintenance	721		721	0.16%	45.21	0.07
19	Telecommunications	1,521		1,521	0.34%	45.21	0.16
20	Postage	1,397		1,397	0.32%	45.21	0.14
21	Advertising	1,451		1,451	0.33%	45.21	0.15
22	Vegetation Management	1,550		1,550	0.35%	45.21	0.16
23	Computer Equipment & Software	785		785	0.18%	45.21	0.08
24	Gross operating expenses	61,504		59,381			
25	Less: GEC	(1,900)		(1,900)	-0.43%	42.90	(0.18)
26	Net Operating Expenses	59,604		57,481			
27	Less: Non-Regulated Expenses	(1,714)		(1,714)	-0.39%	44.95	(0.17)
28	**Regulated Operating Expenses**	57,890		55,767			
29							
30							
31	**Purchased Power**	351,942	2,011	349,931	79.26%	35.79	28.37
34							
35							
36	**Current Income Tax**						
44	Total Tax	20,618	(1,287)	21,905			
45	Plus: Tax Effects of Non-Regulated Expenses	549		549			
46	Regulated Current Income Tax	21,167		22,454	5.09%	17.18	0.87
47							
48							
51	**Municipal Tax Paid**			13,346	3.02%	(125.55)	(3.80)
52							
53							
54	**Cash Operating Expenses in CWC Allowance**			441,498	100.00%		**30.28**
55							
56	**Costs Excluded from CWC Allowance**						
57	Return on Rate Base	79,383					
58	Depreciation Expense	43,341					
59	OPEBs Accrual	5,930					
60	Amortization of Cost Recovery Deferrals	3,861					
61		132,515					
62							
63	**2010 Revenue Requirement**	563,514					
64							

65 [1] Represents items that are not reoccurring cash operating expenses.
66 [2] Includes $199,000 related to the amortization of 2008 hearing costs, $379,000 related to the amortization of conservation costs, conservation program
67 cost rebates of $581,000 and 2010 hearing costs of $750,000.

Newfoundland Power Inc.

2010 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(72,171)	(24.50)	(4,844)
2	Other Billings	(1,427)	66.17	259
3	Purchased Power	45,491	40.26	5,018
4	Operating Expenses	2,492	0.42	3
5				**436**
6				
7				
8				
9				
10				

11 [1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2010 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	37.55
2	Expense Lag Days (Schedule 2)	(30.28)
3	Net Lag Days	7.27
4		
5	CWC Factor (7.28 days divided by 365 days)	2.0%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	441,498
13	CWC Factor	2.0%
14		8,830
15	HST Adjustment (Schedule 3)	436
16	**CWC Allowance**	**9,266**

2008 Pension Valuation

April 2009

NEWFOUNDLAND POWER INC. RETIREMENT INCOME PLAN

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2008

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Newfoundland and Labrador Pension Authorities:
Registration Number: 75241
Canada Revenue Agency Registration Number: 0486365

Consulting. Outsourcing. Investments.

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Summary of Results

Going-Concern Financial Position	**31.12.08**	**31.12.05**
Actuarial value of assets	$251,431,000	$210,945,000
Actuarial liability	($241,063,000)	($225,405,000)
Funding excess (Unfunded liability)	$10,368,000	($14,460,000)
Solvency Financial Position	**31.12.08**	**31.12.05**
Actuarial value of assets net of termination expenses	$222,689,000	$223,170,000
Solvency liability	($229,622,000)	($216,161,000)
Solvency excess (deficiency)	($6,933,000)	$7,009,000
Solvency ratio	92.4%	100%
Wind-up Financial Position	**31.12.08**	**31.12.05**
Market value of assets net of termination expenses	$212,059,000	$223,170,000
Total wind-up liability	($229,622,000)	($216,161,000)
Wind-up excess (deficiency)	($17,563,000)	$7,009,000
Funding Requirements (annualized)	**2009**	**2006**
Total current service cost	$4,616,000	$4,636,000
Estimated member's required contributions	($1,298,000)	($1,265,000)
Estimated employer's current service cost	$3,318,000	$3,371,000
Employer's current service cost as a percentage of members' pensionable earnings	10.37%	10.44%
Minimum special payments	$1,548,000	$2,800,000
Estimated minimum employer contribution for year	$4,866,000	$6,171,000
Estimated maximum employer contribution for year	$20,881,000	$17,831,000

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Introduction

Report on the Actuarial Valuation as at December 31, 2008

To NEWFOUNDLAND POWER INC.

At your request, we have conducted an actuarial valuation of the Newfoundland Power Inc. Retirement Income Plan, sponsored by Newfoundland Power Inc., (the "Company") as at December 31, 2008. We are pleased to present the results of the valuation.

The purpose of this valuation is to determine:

- the funded status of the plan as at December 31, 2008 on going-concern and solvency bases, and

- the minimum and maximum funding requirements from 2009.

The next actuarial valuation of the plan will be required as at a date not later than December 31, 2011 or as at the date of an earlier amendment to the plan, in accordance with the minimum requirements of the *Pension Benefits Act (Newfoundland and Labrador)*.

There is a solvency ratio of 92.4% as at December 31, 2008. As such, the minimum monthly contribution that Newfoundland Power Inc. must make to the plan from 2009 to 2011 is as follows:

Monthly Employer Contributions
For current service: 10.37% of members' pensionable earnings
Minimum additional special payments for solvency: $129,000

On the basis of the members' estimated pensionable earnings we have estimated the minimum total employer contribution for 2009 to be $4,866,000 or $405,500 per month. We have estimated the total members' contribution for 2009 to be $1,298,000.

The maximum contributions that Newfoundland Power Inc. may make to the plan in 2009 is $20,881,000 which is comprised of the Newfoundland Power Inc. current service cost plus the greater of the going-concern deficit and the wind-up deficiency.

The plan is not fully funded on a wind-up basis. Even if the sponsor contributes in accordance with the funding requirements described in this valuation report, the assets of the plan may be less than the liabilities of the plan upon wind, since solvency assets have been smoothed in determining the minimum solvency special payments.

Emerging experience, including the growth of wind-up liabilities compared to the plan's assets (including future contributions and investment returns), will affect the wind-up funded position of the plan.

Since the date of the previous valuation, the plan has been amended as follows:

- Effective July 1, 2006, the plan was amended to provide for an increase in pensions being paid to certain pensioners.
- Provide an early retirement window for certain members to make an election to retire on or before July 31, 2007
- To provide for postponed retirement and amend the definition of "Disability".

A summary of the plan provisions is provided in Appendix D.

We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2005, except for a change in the assumed mortality rates. This change has resulted in a decrease of $2,828,000 in the actuarial liability and of $52,000 in the annual employer current service cost.

The solvency and wind-up assumptions have been updated to reflect market conditions at the valuation date. We have changed the method for calculating the adjusted solvency assets from a market value method to a market-related value method. This change resulted in an increase of $10,630,000 in the adjusted solvency asset value.

The methods and assumptions used for purposes of this valuation are described in Appendix B. All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the pension plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

After checking with representatives of Newfoundland Power Inc., to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

We have assumed that all plan assets are available to cover the plan liabilities presented in this report.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Newfoundland and Labrador)*.

The information contained in this report was prepared for Newfoundland Power Inc. for its internal use and for filing with Newfoundland and Labrador and with the Canada Revenue Agency, in connection with our actuarial valuation of the plan. This report is not intended or necessarily suitable for other purposes.

This report will be filed with the pension authorities in Newfoundland and Labrador and with the Canada Revenue Agency.

Respectfully submitted,

Armando Fernandes	Anil Narale
Fellow of the Society of Actuaries	Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries	Fellow of the Canadian Institute of Actuaries
15 April 2009	15 April 2009
Date	Date

Newfoundland Power Inc. Retirement Income Plan
Registration number in Newfoundland and Labrador: 75241
Registration number with the Canada Revenue Agency: 0486365

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Financial Position of the Plan

Valuation Results – Going-concern Basis

When conducting a valuation on a going-concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the plan will be maintained indefinitely.

Financial Position

The results of the valuation as at December 31, 2008, in comparison with those of the previous valuation as at December 31, 2005 are summarized as follows:

Financial Position – Going-concern Basis

	31.12.08	**31.12.05**
Actuarial value of assets (adjusted market value)	$251,431,000	$210,945,000
Actuarial liability		
Present value of accrued benefits for:		
▪ active members	$125,109,000	$103,773,000
▪ pensioners and survivors	$115,478,000	$121,345,000
▪ deferred pensioners	$476,000	$287,000
Total liability	$241,063,000	$225,405,000
Funding excess (unfunded liability)	$10,368,000	($14,460,000)

Reconciliation of Financial Position

The plan's financial position, a funding excess of $10,368,000 as at December 31, 2008, is reconciled with its previous position, an unfunded liability of $14,460,000 as at December 31, 2005, as follows:

Reconciliation of Financial Position

Funding excess (Unfunded liability) as at 31.12.05	($14,460,000)
Interest on funding excess (unfunded liability) at 6.00% per year to 31.12.08	($2,762,000)
Net experience gains (losses) over 2006 - 2008*	$9,570,000
Employer's special payments to eliminate the unfunded liability	$18,321,000
Impact of changes in assumptions and methods	$2,828,000
Impact of Cost Certificates as at 31.12.2008	
-Ad-hoc Pension Increases at July 1, 2006	($3,433,000)
Net impact of other elements of gains and losses	$304,000
Funding (Unfunded liability) as at 31.12.08	$10,368,000

* Net experience gains (losses) are detailed below.

Plan Experience

The main assumptions are compared with actual experience since the previous valuation as at December 31, 2005:

Plan Experience

	Impact Gain (Loss)
Investment return	$7,722,000
Increases in pensionable earnings and YMPE	($560,000)
Retirements	$548,000
Terminations of employment	$306,000
Mortality	
▪ pre-retirement	$182,000
▪ post retirement	$1,372,000
Net experience gains (losses)	$9,570,000

Valuation Results – Solvency Basis

When conducting a solvency valuation, we determine the relationship between the respective values of the plan's assets and its liabilities on a solvency basis, determined in accordance with the *Pension Benefits Act (Newfoundland and Labrador)*. The values of the plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the plan were wound up and settled on the valuation date. The circumstances in which the plan wind-up is assumed to have taken place are as follows: total plan wind-up in conjunction with cessation of the Plan sponsor's operation.

As at December 31, 2008, the solvency ratio of the plan, being the ratio of solvency assets to solvency liabilities, is 92.4%. The plan's solvency position as at December 31, 2008, in comparison with that of the previous valuation as at December 31, 2005, is determined as follows:

Solvency Position

	31.12.08	**31.12.05**
Market value of assets	$212,279,000	$223,370,000
Termination expense provision	$(220,000)	$(200,000)
1. Solvency assets	$212,059,000	$223,170,000
Solvency smoothing asset adjustment:		
Averaging method adjustment	$10,630,000	$0
Present value of special payments for next five years	$0	$0
2. Adjusted solvency assets	$222,689,000	$223,170,000
Actuarial liability		
Present value of accrued benefits for:		
▪ active and disabled members	$102,252,000	$78,763,000
▪ pensioners and survivors	$126,702,000	$137,038,000
▪ deferred pensioners	$668,000	$360,000
3. Total liability	$229,622,000	$216,161,000
Solvency excess (shortfall) (2. - 3.)	($6,933,000)	$7,009,000
Solvency ratio (1. ÷ 3.)	92.4%	100%

Payment of Benefits

Since the degree of solvency is less than 100%, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the *Pension Benefits Act (Newfoundland and Labrador)* to allow for the full payment of benefits. Otherwise, the plan administrator should take the actions prescribed by the *Act*.

Financial Position on a Wind-up Basis

The plan's hypothetical wind-up position as of December 31, 2008 assuming circumstances producing the maximum wind-up liabilities on the valuation date, is determined as follows:

Wind-up Position

	12.31.08
Market value of assets	$212,279,000
Termination expense provision	($220,000)
Wind-up assets	$212,059,000
Present value of accrued benefits for:	
▪ active members	$102,252,000
▪ pensioners and survivors	$126,702,000
▪ deferred pensioners	$668,000
Total wind-up liability	$229,622,000
Wind-up excess (deficiency)	($17,563,000)

Impact of Plan Wind-up

In our opinion, the value of the plan's assets would be less than its actuarial liabilities if the plan were to be wound up on the valuation date.

Specifically, actuarial liabilities would exceed the market value of plan assets by $17,563,000. This calculation includes a provision for termination expenses that might be payable from the pension fund.

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Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members during 2009, in comparison with the corresponding value determined in the previous valuation as at December 31, 2005, is summarized below:

Employer's Current Service Cost

	2009	**2006**
Total current service cost	$4,616,000	$4,636,000
Estimated members' required contributions	($1,298,000)	($1,265,000)
Estimated employer's current service cost	$3,318,000	$3,371,000
Employer's current service cost expressed as a percentage of members' pensionable earnings	10.37%	10.44%

An analysis of the changes in the employer's current service cost follows:

Changes in Employer's Current Service Cost

Employer's current service cost as at 31.12.05	10.44%
Demographic changes	0.18%
Changes in assumptions and methods – mortality table	-0.25%
Employer's current service cost as at 31.12.08	10.37%

Special Payments

Going-concern Basis

Due to the experience gain arising since the previous valuation, there is no unfunded liability as at December 31, 2008, therefore the monthly special payments for going-concern purposes determined in the previous valuation are no longer required.

Solvency Basis

In accordance with the *Pension Benefits Act (Newfoundland and Labrador)*, the solvency shortfall of $6,933,000 must be eliminated by special payments within five years. The present value of the existing special payments due in the next five years is determined as follows:

Minimum Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment	Present Value of Remaining Payments as at 31.12.08
Solvency	Dec. 31, 2008	$129,000	Dec. 31, 2013	$6,933,000
Total		$129,000		$6,933,000

Total Special Payments

The following minimum monthly special payments must be made to the plan to eliminate any unfunded liability and any solvency shortfall as at December 31, 2008, within the periods prescribed by the *Pension Benefits Act (Newfoundland and Labrador)*.

Minimum Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Solvency	Dec. 31, 2008	$129,000	Dec. 31, 2013
Total		$129,000	

Employer Contributions

There is a solvency deficit of $6,933,000 and a solvency ratio of 92.4% as at December 31, 2008. As such, the minimum monthly contribution that Newfoundland Power Inc. must make to the plan from 2009 to 2011 is as follows:

Monthly Employer Contributions

For current service: 10.37% members' required contributions
Minimum additional special payments for solvency: $129,000

On the basis of the members' estimated pensionable earnings we have estimated the minimum total employer contribution for 2009 to be $4,866,000 or $405,500 per month. We have estimated the total members' contributions for 2009 to be $1,298,000.

Maximum Eligible Contributions

The maximum eligible employer contribution is equal to the Newfoundland Power Inc. current service cost plus the greater of the going-concern unfunded liability and the wind-up deficiency. We have estimated the maximum eligible annual contribution for 2009 to be $20,881,000 as at December 31, 2008. The portion of this contribution representing the payment of the wind-up deficiency $6,933,00 can be increased with interest at 4.67% per year, from December 31, 2008 to the date the payment is made.

Estimated Minimum Employer's Contributions
Until December 31, 2011

Year Ending	Current Service Cost	Minimum Special Payments	Minimum Employer's Contributions
2009	$3,318,000	$1,548,000	$4,866,000
2010	$3,451,000	$1,548,000	$4,999,000
2011	$3,589,000	$1,548,000	$5,137,000

Contributions for current service must be made within the month following the month to which they apply. Contributions for special payments must be made no less frequently than quarterly.

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Actuarial Opinion

With respect to the Actuarial Valuation as at December 31, 2008
of the Newfoundland Power Inc. Retirement Income Plan
Newfoundland and Labrador Registration 75241
Canada Revenue Agency 0486365

Based on the results of this valuation, we hereby certify that, as at December 31, 2008:

- The employer's current service cost for 2009 and subsequent years, up to the next actuarial valuation should be calculated as rate 10.37% of members' pensionable earnings.

- The employer's current service cost 2009 is estimated to be $3,318,000. Member-required contributions for 2009 are estimated to be $1,298,000.

- There is a going-concern excess of $10,368,000 as at December 31, 2008 on the basis of the assumptions and methods described in this report. No special payments are required for going-concern purposes.

- The plan would be fully funded on a solvency basis if its assets were augmented by $6,933,000. In order to comply with the provisions of the *Pension Benefits Act (Newfoundland and Labrador)*, the solvency deficiency must be liquidated by monthly special payments at least equal to the amounts indicated, and for the periods set forth, below:

Monthly Solvency Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Solvency	Dec. 31, 2008	$129,000	Dec. 31, 2013
Total		$129,000	

- The solvency liabilities used to determine the solvency status of the plan do not exclude any benefit provided under the plan.

- We have included in the solvency liabilities the value of all benefits that may be contingent upon the circumstances of the postulated plan wind-up. The circumstances in which the plan wind-up is assumed to have taken place are as follows: plan wind-up in conjunction with cessation of plan sponsor's operations.

- The solvency ratio of the plan is 92.4%.

- In our opinion,
  - the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,
  - the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the plan as at December 31, 2008 on going-concern and solvency bases, and determining the minimum funding requirements, and
  - the methods employed in the valuation are appropriate for the purposes of determining the funded status of the plan as at December 31, 2008 on going-concern and solvency bases, and determining the minimum funding requirements.

- This report has been prepared, and our opinions given, in accordance with accepted actuarial practice.

- All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

Armando Fernandes
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

15 April 2009

Date

Anil Narale
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

15 April 2009

Date

Appendix A

Plan Assets

Sources of Plan Asset Data

The pension fund is managed by Barclays Global Investors Canada Limited and held in trust with RBC Dexia Investor Services ("RBC Dexia").

We have relied upon fund statements prepared by RBC Dexia and data provided by Newfoundland Power Inc., for the period from December 31, 2005 to December 31, 2008.

Reconciliation of Plan Assets

The pension fund transactions for the period from December 31, 2005 to December 31, 2008 are summarized as follows:

Reconciliation of Plan Assets (Market Value)

	2006	2007	2008
January 1	$223,370,000	$250,226,000	$259,731,000
PLUS			
Members' contributions	$1,216,000	$1,216,000	$1,193,000
Company's contributions	$3,371,000	$3,598,000	$3,847,000
Company's past service contributions	$7,540,000	$7,307,000	$1,578,000
Investment income	$27,331,000	$10,420,000	($40,521,000)
	$39,458,000	$22,541,000	($33,903,000)
LESS			
Pensions paid	$11,959,000	$11,983,000	$12,057,000
Lump-sum refunds	$336,000	$613,000	$869,000
Administration fees	$307,000	$440,000	$303,000
	$12,602,000	$13,036,000	$13,229,000
December 31	$250,226,000	$259,731,000	$212,599,000

This asset value is adjusted to reflect in-transit benefit payments of $320,000. The resulting market value is $212,279,000.

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator adopted a statement of investment policy and objectives which was last revised effective April, 2007. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the asset mix, and the actual asset mix as at December 31, 2008, are provided for information purposes:

Distribution of the Market Value of the Fund by Asset Class

	Investment Policy		
	Minimum	**Target**	**Maximum**
Canadian Equities	35%	40%	45%
US Equities	10%	15%	20%
Non-North American Equities	0%	5%	10%
Fixed Income	35%	40%	45%
Cash and short term	0%	0%	5%
		100%	

Performance of Fund Assets

The average return on the adjusted market value, net of expenses, since the last valuation at December 31, 2005 was 7.05% per year. This rate exceeds the assumed investment return of 6.0% by 1.05% per year.

Appendix B

Actuarial Methods and Assumptions

Actuarial Valuation Methods – Going-concern Basis

Valuation of Assets

For this valuation, we have continued to use an adjusted market-value method to determine the actuarial value of assets. Under this method, investment gains (losses) arising during a given year are spread on a straight-line basis over three years. As a result, the asset value produced as at December 31, 2008 recognizes the following percentages of the investment gains (losses) that arose during the past years:

	Recognized	Deferred
2006 and before:	100%	0%
2007:	67%	33%
2008:	33%	67%

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values. To the extent that more capital gains than losses will arise over the long term, the actuarial value will tend to be lower than the market value.

The actuarial value of the assets, determined as at December 31, 2008 under the adjusted market value method, is $251,751,000.

This value was derived as follows:

Smoothed Value of Assets as at 31.12.08

Market value of assets		$212,599,000
LESS		
Unrecognized investment gains/(losses)	2007: ($5,019,000) x 33% =	($1,673,000)
	2008: ($56,219,000) x 67% =	($37,479,000)
		($39,152,000)
Actuarial value of assets		$251,751,000

This actuarial value of assets is adjusted to reflect in-transit benefit payments of $320,000. The resulting going-concern actuarial value of assets is $251,431,000.

Valuation of Actuarial Liabilities

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going-concern valuation, we have continued to use the *projected unit credit actuarial cost method*. Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability*.

The *funding excess* or *unfunded liability*, as the case may be, is the difference between the market actuarial value of assets and the actuarial liability. An unfunded liability will be amortized over no more than 15 years through special payments as required under the *Pension Benefits Act Newfoundland and Labrador*. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial funding method aims at keeping the plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

Current Service Cost

The *current service cost* is the actuarial present value of projected benefits to be paid under the plan with respect to service during the year following the valuation date.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Given that the Newfoundland Power Retirement Income Plan is closed to new entrants, the average age of the group is expected to increase in the future and therefore, the current service cost of the group, expressed as a percentage of the members' pensionable earnings, can be expected to increase as well.

Employer's Contribution

Accordingly, the employer's contributions for this purpose are determined as follows:

Employer's Contributions

With a funding excess	With an unfunded liability
Current service cost	Current service cost
MINUS	PLUS
Any funding excess applied to cover the employer's current service cost	Payments to amortize any unfunded liability

Actuarial Assumptions – Going-concern Basis

The actuarial value of benefits 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.

In this valuation, we have used the same assumptions as in the previous valuation except as noted. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations. For this valuation, we have used the following assumptions.

Economic Assumptions

Investment Return

We have assumed that the investment return on the actuarial value of the fund will average 6.0% per year over the long term. We have based this assumption on an expected long-term return on the pension fund less a margin for adverse deviations. The expected long-term return on the pension fund was determined for the target asset mix specified in the plan's investment policy consistent with market conditions applicable on the valuation date.

Expenses

The assumed Investment Return reflects an implicit provision for expenses.

Increases in the YMPE

Since the benefits provided by the plan depend on the final average Year's Maximum Pensionable Earnings (YMPE) under the Canada Pension Plan, it is necessary to make an assumption about increases in the YMPE for this valuation. We have assumed that the YMPE will increase at the rate of 3.5% per year. The increase was applied from the 2009 level of the YMPE of $46,300.

Increases in the Maximum Pension Permitted under the Income Tax Act

The *Income Tax Act* stipulates that the maximum pension that can be provided under a registered pension plan is $2,444.44 per year of service in 2009, and automatically, starting in 2010, this limit will increase in accordance with general increases in the average wage.

For this valuation, we have assumed that the maximum pension payable under the plan is $2,444.44 per year of service in 2009 and will increase starting in 2010, at the assumed rate of wage increase of 3.5% per year.

Increases in Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken salary rates at December 31, 2008 and assumed that such salaries will increase at 4.0% per year.

Indexation of Pensions in Payment

In this valuation, no assumptions have been made with respect to indexing pensions in payment.

Demographic Assumptions

Retirement Age

Because early retirement pensions are reduced in accordance with a formula, the retirement age of plan members has an impact on the cost of the plan.

We have assumed that members will retire one year after the later of the date they would obtain age 60 and age plus service would total 95 (date which the member is entitled to an unreduced early retirement) but not later than age 65.

Termination of Employment

We have made an allowance for projected benefits payable on the termination of employment before retirement for reasons other than death.

We have used termination rates that are based on 50% of the turnover rates under the Ontario Light termination table. We have not used rates of termination after age 39.

Sample rates are shown in the following table:

Termination Rates

Age	Percentage
25	5.0%
30	2.8%
35	1.6%
39	1.2%
40 - 64	0.0%

Mortality

The actuarial value of the pension depends on the lifetime of the member.

We have assumed mortality rates, both before and after retirement, in accordance with the 1994 Uninsured Pension Mortality Generational Table. According to this table, the life expectancy at age 65, as of the valuation date, is 19.4 years for males and 22.0 years for females.

In the last valuation, the Group Annuity Reserving (GAR) Table for 1994 was used to model mortality rates.

Disability

We have not made an allowance for incidence of disability prior to retirement.

Family Composition

Benefits in case of death, before and after retirement, depend on the plan member's marital status.

For this valuation, we have assumed that 80% of plan members will have an eligible spouse on the earlier of death or retirement, and that the male partner will be three years older than the female partner.

Actuarial Valuation Methods and Assumptions – Solvency and Impact of Plan Wind-up

For this valuation, we have used an adjusted market-value method to determine the actuarial value of assets. Under this method, investment gains (losses) arising during a given year are spread on a straight-line basis over three years with the resulting actuarial value of assets within a 5% corridor of the market-value of assets. As a result, the asset value produced as at December 31, 2008 recognizes the following percentages of the investment gains (losses) that arose during the past years:

	Recognized	**Deferred**
2006 and before:	100%	0%
2007:	67%	33%
2008:	33%	67%

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values. To the extent that more gains than losses will arise over the long term, the actuarial value will tend to be lower than the market value.

The actuarial value of the assets, determined as at December 31, 2008 under the adjusted market value method, is $223,229,000.

This value was derived as follows:

Smoothed Value of Assets as at 31.12.08

Market value of assets			$212,599,000
LESS			
Unrecognized investment gains/(losses)	2007: ($1,269,000) x 33% =	($423,000)	
	2008: ($52,370,000) x 67% =	($34,913,000)	
		($35,336,000)	
5% corridor	$212,599,000 x 5% =	$10,630,000	
Unrecognized investment gains/(losses) limited by the 5% corridor			($10,630,000)
Actuarial value of assets			$223,229,000

This actuarial value of assets is adjusted to reflect in-transit benefit payments of $320,000. The resulting solvency actuarial value of assets is $222,909,000.

In the last valuation, we used the market value of the plan's assets in our valuation of the plan for solvency purposes.

To determine the solvency actuarial liability, we have valued those benefits that would have been paid had the plan wound up on the valuation date, with all members fully vested in their accrued benefits. The circumstances in which the plan wind-up is assumed to have taken place are as follows: total wind-up in conjunction with cessation of the plan sponsor's operations.

Benefits are assumed to be settled through a lump sum transfer for *active and disabled members under 55 years of age at December 31, 2008.* The value of the benefits accrued on December 31, 2008, for such members is based on the assumptions described in Section 3800 – *Pension Commuted Values* of the Canadian Institute of Actuaries Standards of Practice *(the April 2009 Transfer Value Standard)* applicable for benefits expected to be settled through transfer in accordance with relevant portability requirements after April 1, 2009. The Canadian Institute of Actuaries permits early implementation of this Standard for the purposes of solvency and hypothetical wind up valuations as at December 31, 2008. We have confirmed this application of the Standard in this manner is permitted by the Financial Services Regulation Division of Newfoundland and Labrador.

Benefits are assumed to be settled through the purchase of annuities for *active and disabled members over 55 years of age at December 31, 2008.* The value of the benefits accrued on December 31, 2008, for such members are based on an estimate of the cost of settlement through purchase of annuities.

Assumptions are as follows:

Actuarial Assumptions

Mortality rates for benefits to be settled through lump sum transfer:	UP-1994 projected to 2020
Mortality rates for benefits to be settled through annuity purchase:	UP-1994 projected to 2015
Interest rates for benefits to be settled through lump sum transfer:	4.20% per year for the first 10 years following 31.12.08, 5.70% per year thereafter
Interest rates for benefits to be settled through immediate annuity purchase:	4.85% per year
Interest rates for benefits to be settled through deferred annuity purchase:	4.45% per year
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going-concern valuation
Maximum pension limit:	2.35% per year for the first 10 years following 31.12.08, 2.96% thereafter
Termination expenses:	$220,000

In a solvency valuation, the accrued benefits are based on the member's final average earnings on the valuation date; therefore, no salary projection is used. Also the employment of each member is assumed to have terminated on the valuation date, therefore, no assumption is required for future rates of termination of employment.

To determine the solvency position of the plan, the provision for expenses payable from the plan's assets is in respect of actuarial, administration and legal expenses that would be incurred in terminating the plan.

Because the settlement of 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 the hypothetical wind-up being contested. The provision for termination expenses does not include any transaction fees related to the liquidation of the plan's assets and any reduction in the value of the plan's equity assets resulting from their liquidation.

Appendix C

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2008, provided by Newfoundland Power Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

Membership Data

	31.12.08	31.12.05
Active Members		
Number	492	538
Total pensionable earnings	$32,840,800	$32,294,554
Average pensionable earnings for following year	$66,750	$60,027
Average years of pensionable service	24.2 yrs.	21.4 yrs.
Average age	49.6	46.8
Accumulated contributions with interest	$26,145,223	$22,913,699
Disabled Members		
Number	24	19
Total pensionable earnings	$1,157,534	$758,994
Average pensionable earnings for following year	$48,231	$39,947
Average years of pensionable service	25.5 yrs.	22.6 yrs.
Average age	54.3	51.3
Accumulated contributions with interest	$882,195	$463,783
Deferred Pensioners		
Number	8	8
Total annual pension	$101,148	$74,935
Average annual pension	$12,644	$9,367
Average age	43.8	49.3
Pensioners and Survivors		
Number	660	673
Total annual lifetime pension	$8,962,775	$8,551,945
Total annual bridge pension	$2,928,499	$3,374,172
Average annual lifetime pension	$13,580	$12,707
Average age	69.1	67.3

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

Reconciliation of Membership

	Active Members	Disabled Members	Deferred Pensioners	Pensioners	Surviving Spouses	Total
Total at 31.12.2005	538	19	8	542	131	**1,238**
To disabled	(8)	8				**-**
Terminations						
▪ Transfers						
▪ Paid out	(11)	(1)	(2)			**(14)**
▪ Deferred pensions	(4)	(1)	5			**-**
▪ Pending						
Deaths						
▪ Payments pending	(2)					**(2)**
▪ No benefits outstanding	(1)	(1)	(1)	(15)	(24)	**(42)**
▪ With beneficiary				(35)	35	**-**
Retirements	(20)		(2)	22		**-**
Data Correction	-			4		**4**
Total at 31.12.2008	492	24	8	518	142	**1,184**

The distribution of the active members by age and pensionable service as at December 31, 2008, is summarized as follows:

Distribution of Active Members
By Age Group and Pensionable Service as at 31.12.08

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30 +**	**Total**
Under 20								
20 - 24								
25 - 29								
30 - 34	1	10	1					12
35 - 39		10	10	4				24
40 - 44		10	24	25	25	1		85
45 - 49		3	10	20	28	38	2	101
50 - 54		4	4	18	20	44	86	176
55 - 59			1	4	8	6	65	84
60 - 64			1	2	1	1	5	10
65 +								
Total	**1**	**37**	**51**	**73**	**82**	**90**	**158**	**492**

The distribution of the inactive members by age as at December 31, 2008, is summarized as follows:

Distribution of Inactive Members
By Age Group as at 31.12.08

	Deferred Pensioners		Pensioners and Survivors			
Age	**Number**	**Average Pension**	**Number**	**Average Pension**	**Number**	**Average Bridge**
25 – 29						
30 - 34	1	$10,432				
35 - 39	1	$7,210				
40 - 44	4	$14,315				
45 - 49						
50 - 54	1	$10,159	14	$20,170	13	$15,512
55 - 59	1	$16,087	85	$18,509	77	$13,145
60 - 64			156	$15,343	138	$12,425
65 - 69			122	$12,734		
70 - 74			125	$12,100		
75 - 79			78	$10,914		
80 - 84			47	$10,383		
85 - 89			24	$9,852		
90 - 94			6	$8,123		
95 - 99			3	$7,683		
100 – 104						
TOTAL	8	$12,644	660	$13,580	228	$12,844

Appendix D

Summary of Plan Provisions

Introduction

The Newfoundland Power Inc. Retirement Income Plan became effective April 1, 1984.

This valuation is based on the plan provisions in effect on December 31, 2008. The following is a summary of the plan's main provisions in effect on December 31, 2008. It is not intended as a complete description of the plan.

Eligibility for Membership

Each employee hired before the effective date of this plan is eligible to participate. Each employee hired on or after the effective date shall become a member of the plan on the first day of employment.

Membership was optional for employees transferred from an affiliated company, for employees hired or designated as manager or executive, and for non-bargaining unit employees hired on or after August 1, 2003.

However, effective May 1, 2004, the plan was closed to new entrants.

Contributions

The members are contributing to the plan at the rate of 3 1/3% of their salary up to the Year's Maximum Pensionable Earnings (YMPE) and 5% of their salary in excess of the YMPE. For 1984, the members were contributing at the rate of 60% (2%/3%) of their full rate starting on April 1st.

No contributions shall be required to be made beyond 35 years of service. However, members may elect to make required contributions beyond completion of 35 years, up to the maximum of $1,000, in order to attain higher final average earnings.

Interest shall be credited on member contributions at a rate not less than the rate at issue of the last Canada Savings Bond issued prior to the start of the calendar year. Effective January 1, 1997, interest shall be credited based on the average of the yields on 5-year personal fixed term chartered bank deposits published in the Bank of Canada Review as CANSIM Series B14045, the averaging to be done over a reasonable recent period, not exceeding twelve months.

Additional voluntary contributions are not permitted after January 1, 1992.

The Company is contributing the remaining cost for current service and the cost for past service.

The YMPE, or Year's Maximum Pensionable Earnings, refers to the maximum annual amount of earnings upon which an employee and an employer contribute to the Canada/Québec Pension Plan (C/QPP).

Retirement Dates

Normal Retirement Date

The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday.

Postponed Retirement

An active member may not postpone retirement beyond the normal retirement age of 65 years.

Retirement Benefits

Normal Retirement

Upon normal retirement a member is entitled to an annual pension equal to 1 1/3% of the average of his best 36 months of earnings during which contributions were made up to the final average YMPE plus 2% of such best average earnings in excess of the average of the final 36 months YMPE for each year of credited service (up to a maximum of 35 years).

Early Retirement Pension

An early retirement pension without reduction is payable if the member has both attained age 60 and has a combined total years of age plus service of 95.

An early retirement pension with a subsidized reduction is permissible if the member's age plus service is 85 or greater.

The amount of the reduction is:

1. if the member's total years of age plus service total 95 or more – 1/4% for each month before age 60, and.

2. if the member's total years of age plus service total less than 95 - 1/3% for each month before the earliest date at which the member could have elected unreduced retirement.

Early retirement is permitted after attaining age 55 with a pension that is actuarially reduced from age 65.

Maximum Pension

The total annual pension payable from the plan upon retirement, death or termination of employment cannot exceed the lesser of:

- 2% of the average of the best three consecutive years of total compensation paid to the member by the Company, multiplied by total credited service; and

- $2,000 or such other maximum permitted under the *Income Tax* Act, multiplied by the member's total credited service.

Survivor Benefits

Death Before Retirement

On death of a member before retirement, his/her surviving spouse shall be entitled to 55% of his/her accrued pension payable immediately for life.

If the surviving spouse is more than 15 years younger than the participant, the entitlement is reduced by 1.5% of each full year in excess of 15.

If there is no surviving spouse, the beneficiary shall receive a refund of the member's accumulated contributions with interest.

Notwithstanding the above, if a member or former member who has completed 2 years of membership in the plan dies after December 31, 1996, the surviving spouse or beneficiary is entitled to the minimum death benefit equal to the actuarial value of the vested pension benefits accrued after December 31, 1996.

Death After Retirement

The normal form of payment for a member with a spouse at retirement is a joint and survivor pension with 55% of the member's pension continuing to the surviving spouse. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.

The normal form of payment for a member without a spouse is pension payable for the member's lifetime. However, in no case shall the total of pension payments paid to the member prior to death be less than the member's accumulated contributions with interest at pension commencement.

Termination Benefits

Pension Benefit Accrued Prior to January 1, 1997

Prior to Completion of 5 Years of Service

A member who terminates his/her employment after December 31, 1996 but prior to completing 5 years of service will receive a refund of his/her accumulated contributions made prior to January 1, 1997 with interest.

After Completion of 5 Years of Service

1. A member who terminates his/her employment after December 31, 1996 and after completing 5 years of service will receive a termination benefit equal to the greater of:

   - 2 times his accumulated member's contributions made prior to January 1, 1997 with interest, or
   - the actuarial value of his vested pension accrued prior to January 1, 1997.

2. For a member with age plus service totalling 45 or more, the member has the choice of receiving:

   - a deferred pension, or
   - a refund of his contributions and the balance of his/her termination benefit, as determined in section 1 above, transferred to a locked-in RRSP.

3. Notwithstanding the above, a member who has attained age 45 and has 10 years or more of service is entitled to either a deferred pension or a transfer to a locked-in RRSP of the value of his termination benefits, as determined in section 1 above.

Pension Benefits Accrued After December 31, 1996

Prior to Completion of 2 Years of Membership Service

A member who terminates his/her employment after December 31, 1996 before completing 2 years of membership service will receive a refund of his/her accumulated contributions made after December 31, 1996 with interest ("Post 96 Accumulated Member Contributions").

Completion of 2 Years of Membership Service

1. A member terminates his/her employment after December 31, 1996 with 2 years of membership service will receive the termination benefit equal to the greater of:

   - 2 times his/her Post 96 Accumulated Member Contributions provided he/she has completed 5 years of service; and
   - the sum of:

     - the actuarial value of his pension benefit accrued after December 31, 1996.
     - the excess, if any, of the Post 96 Accumulated Member Contributions over 50% of the actuarial value of his/her pension benefit accrued after December 31, 1996 ("Excess Member Contribution").

2. The Member has the choice of receiving:

   - a deferred pension with respect to his pension benefit accrued after December 31, 1996 plus a refund of his/her Excess Member Contribution; or
   - a refund of his/her Excess Member Contributions plus a transfer of the balance of the termination benefit, as determined under section 1 above, to a locked-in RRSP.

Disability Benefits

During a member's disability the earnings are deemed to be equal to the amount earned at the time of becoming disabled and the member continues to accrue service. A disabled member shall not be required to contribute to the plan. The Company contributes the entire cost of the benefits.

Appendix E

Employer Certification

With respect to the report on the actuarial valuation of the *Newfoundland Power Inc. Retirement Income Plan*, as at December 31, 2008, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official plan documents and of all amendments made up to December 31, 2008, were provided to the actuary,
- the membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the plan for service up to December 31, 2008, and
- all events subsequent to December 31, 2008 that may have an impact on the results of the valuation have been communicated to the actuary.

May 12, 2009
Date

Jocelyn Perry
Signed

Jocelyn Perry
Name
Vice President, Finance & CFO
Newfoundland Power Inc.

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Report on Other Post Employment Benefits

May 2009

Table of Contents

1.0 INTRODUCTION

1.1 Background

Newfoundland Power provides defined benefit and defined contribution pension plans and other post employment benefits ("OPEBs") for its employees. Newfoundland Power's OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependents. Pensions and OPEBs together represent Newfoundland Power's total employee future benefits.

Newfoundland Power effectively recognizes OPEBs costs on a cash basis whereby the annual expense is equal to the retirement allowances and insurance premiums actually paid in the year (the "Cash Method").[1] Newfoundland Power recognizes pension costs using the accrual method (the "Accrual Method").

In the 2008 General Rate Application ("GRA"), the Company filed a report to address the use of the Accrual Method of recognizing OPEBs as an alternative to the Cash Method. [2]

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power to continue using the Cash Method for OPEBs until the matter is given further consideration by the Board at the next GRA.[3]

1.2 Regulatory Context

Newfoundland Power has assessed its OPEBs obligations, including the transitional obligations associated with moving to the Accrual Method and the customer rate implications of this change in accounting policy.

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1 The *Income Tax Act (Canada)* requires that the computation of current income tax reflect the Cash Method of accounting for OPEBs, i.e. only retirement allowances and insurance premiums actually paid are tax deductible.

2 This report was filed in accordance with Order No. P.U. 19 (2003). Page 83 of the Order stated "The Board is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits. The Board recognizes that there are significant transitional obligations associated with this change in accounting policy but once the transitional obligation has been met these costs should decrease. NP should continue to monitor its obligations with respect to employee future benefits and corresponding regulatory practice. The Board will direct NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA. The Board emphasizes such a plan should be presented to the Board as an alternative to the existing method and should address the transitional impact with a view to fulfilling NP's obligation to its employees while at the same time moderating its impact on rates. The Board will then be in a position to consider this alternative accrual method and its specific impacts at the next hearing."

3 Order No. P.U. 32 (2007), page 18.

An actuarial valuation determined the present value of Newfoundland Power's total OPEBs obligation, as of December 31, 2008, to be approximately $59.6 million on an accrual basis.[4]

Table 1 shows the projected growth in Newfoundland Power's total OPEBs obligations over the period 2008 to 2012.

Table 1
Total OPEBs Obligation
Accrual Basis
As of December 31
($millions)

2008	2009	2010	2011	2012
59.6	64.2	68.3	73.0	77.3

As employees accumulate service with the Company, the value of Newfoundland Power's OPEBs obligations will continue to increase.

There are significant transitional obligations associated with moving from the Cash Method to the Accrual Method (i.e., the "Transitional Obligation").[5]

Fully recognizing Newfoundland Power's total OPEBs obligations, including the Transitional Obligation, through adoption of the Accrual Method commencing in 2010 would result in an increase in 2010 revenue requirements of approximately $10.2 million or 1.8%.[6]

1.3 Newfoundland Power's Proposal

Based on its assessment, the Company is proposing a measured transition to the Accrual Method. The proposal in the Application includes features that reasonably mitigate the impact on customer rates of the proposed change.

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[4] The current actuarial valuation of the Company's OPEBs obligations on an accrual basis is found in *Volume 2: Supporting Documents, Tab 5.*

[5] In accordance with GAAP requirements, Newfoundland Power recorded a regulatory asset of $41.1 million associated with the Transitional Obligation on its December 31, 2008 balance sheet. The Transitional Obligation represented by this regulatory asset is projected to grow to approximately $46.2 million by December 31, 2009.

[6] The $10.2 is comprised of $5.6 million to move to the Accrual Method on a tax-effected basis (see Table 8) and $4.6 million for the Transitional Obligation. This assumes the Transitional Obligation is recovered over a 10 year period. The 1.8% customer rate impact equals $10.2 million divided by $568.7 million total customer charges under existing rates from Exhibit 10.

In this Application, Newfoundland Power proposes to:

1. adopt the Accrual Method of accounting for OPEBs costs for regulatory purposes commencing in 2010;
2. tax-effect employee future benefits costs related to OPEBs expense for regulatory purposes commencing in 2010;[7] and
3. defer consideration of the Transitional Obligation of $46.2 million until a further hearing to be determined by the Board.[8]

The Company's proposals, if approved by the Board, will result in an increase in 2010 revenue requirements of approximately 1.0%.

2.0 OPEBs ACCOUNTING POLICY

2.1 The Accrual Method

Under the Accrual Method, OPEBs costs are recognized as an expense as employees earn the benefits that they will receive after retirement. Therefore, OPEBs costs are "accrued" rather than being recognized when benefits are paid.

Conceptually, OPEBs costs are no different than pension costs attributable to defined benefit pension plans. Both are costs of employee future benefits.

Newfoundland Power uses the Accrual Method to recognize pension expense attributable to its defined benefit pension plans for both financial reporting and regulatory purposes. Pension expense is actuarially determined and reflects management's best estimates with respect to matters such as the expected performance of pension plan assets, future salary escalation and the retirement ages of employees. Under the Accrual Method, OPEBs expense would be calculated in a similar manner.

Newfoundland Power proposes to adopt the Accrual Method of accounting for OPEBs costs on a prospective basis for regulatory purposes in 2010.

2.2 Canadian Standards and Practice

2.2.1 Financial Reporting Standards

Canadian generally accepted accounting principles ("GAAP") with respect to the recognition of both defined benefit pension costs and OPEBs costs for financial reporting purposes are set out in section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook.

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[7] Tax-effecting employee future benefits costs mitigates the impact on revenue requirement of adopting the Accrual Method of recognizing OPEBs costs for regulatory purposes. In Order No. P.U. 32 (2007), the Board approved the tax effecting of future benefit costs related to pensions.

[8] If the Company adopts the accrual method of accounting for OPEBs in 2010 as proposed in the Application, the $46.2 million Transitional Obligation will not change.

Pursuant to section 3461, defined benefit pension costs and OPEBs costs would normally be recognized under the Accrual Method for financial reporting purposes.[9]

Prior to 2009, Canadian GAAP contained guidance that effectively permitted the recognition of regulatory assets and liabilities.[10] This effectively allowed Newfoundland Power to continue to recognize OPEBs costs using the Cash Method rather the Accrual Method as required under section 3461.

Effective 2009, the AcSB removed from Canadian GAAP the guidance that permitted recognition of regulatory assets and liabilities. For 2009 and 2010, Canadian regulated utilities effectively rely on U.S. GAAP (particularly, Statement of Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*) which permits recognition of regulatory assets and liabilities on a conceptually similar basis to that allowed under Canadian GAAP prior to 2009. Commencing in 2011, the recognition of regulatory assets and liabilities will be governed by IFRS.[11]

The accumulated OPEBs expense of $41.1 million, as of December 31, 2008, has been recorded as a regulatory asset. This Transitional Obligation represents the amount of incurred OPEBs expense for which recognition, and recovery from customers, has effectively been deferred until future periods.

The Transitional Obligation is forecast to increase to approximately $46.2 million by December 31, 2009.

2.2.2 Financial Reporting and Regulatory Practice

During the 2008 GRA, the Company surveyed regulated Canadian utilities with respect to their OPEBs accounting policy for financial reporting and regulatory purposes. The results of the survey showed that only 6 of 24 Canadian utilities used the Cash Method of accounting for OPEBs.

The Company has surveyed 24 regulated Canadian utilities with respect to accounting for OPEBs. Appendix A provides a list of the surveyed utilities.

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9 Section 3461 of the CICA Handbook became effective on January 1, 2000.

10 CICA accounting guideline AcG-19 titled *disclosures by entities subject to rate regulation* effectively required rate-regulated entities like Newfoundland Power to record regulatory assets and regulatory liabilities on their balance sheets. In compliance with AcG-19, Newfoundland Power reported a regulatory asset (the "Transitional Obligation") and a GAAP liability of $41.1 million with respect to its OPEBs on its December 31, 2008 balance sheet. This actuarially determined amount represents the amount of Newfoundland Power's accumulated benefit obligation for OPEBs that would have been recorded as both an expense and a liability by December 31, 2008 pursuant to section 3461 of the CICA Handbook.

11 In December 2008, the IASB initiated a project on rate-regulated activities. The IASB currently expects to publish an exposure draft concerning the recognition and measurement criteria for regulatory assets and liabilities by July 2009. A final standard is currently expected to be published by the IASB in June 2010.

Table 2 provides the updated survey results.

Table 2
Survey Results
OPEBs Accounting Policy
Financial Reporting and Regulatory Purposes

	Number of Regulatory Jurisdictions	Number of Utilities
Accrual Method	10	22[12]
Cash Method	2	2
		24

The Accrual Method is the mainstream accounting policy for regulated Canadian utilities. Based upon the results of the survey, 22 or 92% use the accrual basis of accounting for the recognition of OPEBs costs.[13] Compared to the survey completed in 2007, the number of utilities using the Cash Method has reduced from 6 to 2.

2.3 Impact of Adopting the Accrual Method

2.3.1 Impact of Accrual Method on Net OPEBs Expense

The forecast impact of adopting the Accrual Method on Newfoundland Power's net OPEBs costs for 2010 is summarized in Table 3.[14]

Table 3
OPEBs Accrual Method
Forecast Impact on Net OPEBs Costs
($millions)

	2010
Cash Method	1.7
Accrual Method	7.4
Increase	5.7

12 Includes Newfoundland and Labrador Hydro ("Hydro"). Two utilities, Northwest Territories Power Corp and Pacific Northern Gas Ltd., use variations of the accrual/cash methods for the recognition of OPEBs and are not reflected in Table 2.

13 The utilities surveyed that use the Cash Method of accounting for OPEBs are FortisAlberta and Gaz Metro Limited Partnership.

14 The *forecast* amounts in Table 3 are based on the OPEB Actuarial Valuation and, in the case of the Accrual Method, GAAP as set out in section 3461 of the CICA Handbook. The calculation of net OPEBs expense under the Accrual Method is consistent with the calculation of net pension expense for the Company's defined benefit pension plans.

Table 3 shows that in 2010 net OPEBs costs under the Accrual Method would be approximately $5.7 million higher than that calculated under the Cash Method.

2.3.2 Impact of Accrual Method on Rate Base

Actual OPEBs payments made by Newfoundland Power in any period is the total of the insurance premiums and retirement allowances paid in the period.

Under the Accrual Method, the excess of OPEBs expense recognized in any period over OPEBs payments made in the period would, in accordance with accounting guidelines, be recorded as a net liability on Newfoundland Power's balance sheet. This net liability (the "Accrued OPEBs Liability") represents, at any date, the amount by which cumulative OPEBs expense recognized to that date has exceeded cumulative OPEBs payments to that date.[15]

Because OPEBs expense under the Cash Method is equal to OPEBs payments, the Accrued OPEBs Liability is also equal to the cumulative difference between (i) OPEBs expense under the Cash Method and (ii) OPEBs expense under the Accrual Method.

Under the asset rate base method ("ARBM"), the Accrued OPEBs Liability serves to decrease Newfoundland Power's rate base. Consistent with the ARBM methodology[16], Newfoundland Power proposes that the Accrued OPEBs Liability be deducted from its rate base commencing in 2010 upon the adoption of the Accrual Method of accounting for OPEBs.[17]

Essentially, the Accrued OPEBs Liability is conceptually similar to the Company's future income tax liability. Both represent expenses recognized in the current period or in prior periods for which payment will not occur until future periods, i.e. both are deferred liabilities. Newfoundland Power's future income tax liability is subtracted from its rate base.[18]

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15 The recognition of OPEBs expense increases the Accrued OPEBs Liability. The OPEBs payments decrease the Accrued OPEBs Liability.

16 In Order No. P.U. 19 (2003), the Board found that the ARBM should replace the invested capital method in determining the rate base for Newfoundland Power.

17 The treatment of Newfoundland Power's Accrued OPEBs Liability as a reduction in rate base would be conceptually consistent with the treatment of the deferred pension asset relating to its defined benefits pension plans. The inclusion of Newfoundland Power's deferred pension asset in its rate base was approved by the Board in Order No. P.U. 19 (2003).

18 See Return 3 in Newfoundland Power's 2008 Annual Report to the Board.

Table 4 provides the forecast impact on 2010 average rate base of the adoption of the Accrual Method.

Table 4
OPEBs Accrual Method
Forecast Impact on Average Rate Base
($millions)

	2010
Accrued OPEBs Liability, Beginning of the Year	-
Net OPEBs Expense, Accrual Method[19]	7.4
Net OPEBs Expense, Cash Method[20]	(1.7)
Accrued OPEBs Liability, End of the Year	5.7
Reduction in Average Rate Base[21]	2.9

The reduction in average rate base shown in Table 4 will reduce Newfoundland Power's permitted return and revenue requirement. In this way, the cash flow benefits associated with the increased net OPEBs expense under the Accrual Method are passed on to customers.

The reduction in rate base that will result from the adoption of the Accrual Method for OPEBs tends to offset the deferred pension asset included in rate base. The deferred pension asset reflects the fact that, under the Accrual Method of pension accounting, pension funding for the defined benefit plans has exceeded pension expense.[22] The cumulative difference is recorded as a deferred asset until it is recognized as pension expense in future periods.

Under the Accrual Method, the opposite is true for OPEBs. The expense is recognized and recovered through customer rates prior to the cash disbursements. The resultant Accrued OPEBs Liability is recorded as a deferred liability until it is extinguished through the payment of OPEBs costs in future periods.

These underlying, and offsetting, dynamics serve to limit the overall rate base impacts relating to the Company's employee future benefits programs when the Accrual Method is used to account for both OPEBs and pension costs.

[19] As per Table 3.
[20] OPEBs payments related to insurance premiums and retirement allowances.
[21] Equals (Accrued OPEBs Liability, Beginning of the Year plus Accrued OPEBs Liability, End of the Year) divided by 2.
[22] Pension funding is actuarially determined. Pension expense is determined in accordance with accounting standards and reflects both the actuary's calculations and management's best estimates. The differences in methodologies result in ongoing differences between pension funding and pension expense.

2.3.3 Impact of Accrual Method on Revenue Requirement

Table 5 sets out, on a forecast basis for 2010, the impact of the Accrual Method on the revenue requirement attributable to OPEBs.

Table 5
OPEBs Accrual Method
Forecast Impact on Revenue Requirement
($millions)

	2010
Operating Expenses	
Increase in Net OPEBs Expense[23]	5.7
Tax Effects[24]	2.7
Increase in Revenue Requirement	8.4
Return on Rate Base	
Rate Base Effects[25]	(0.3)
Tax Effects	(0.1)
Decrease in Revenue Requirement	(0.4)
Increase in Revenue Requirement	8.0

Table 5 shows that the forecast impact of the Accrual Method on revenue requirement in 2010 is $8.0 million.

2.4 Transitional Obligation

Newfoundland Power proposes that the Transitional Obligation, shown as a regulatory asset on its December 31, 2008 balance sheet, be addressed at a further hearing to be determined by the Board.

The Transitional Obligation is the actuarially determined difference between (i) the total OPEBs expense that would have been recognized by the Company pursuant to the Accrual Method since January 1, 2000,[26] and (ii) the total OPEBs expense recognized since that date under the Cash Method. It represents legacy OPEBs costs that have not yet been recovered from customers.

As at the proposed January 1, 2010 adoption date for the Accrual Method of accounting for OPEBs, the forecast Transitional Obligation is approximately $46.2 million.

23 As per Table 3.
24 Based on Newfoundland Power's marginal income tax rate of 32 percent for 2010.
25 Equals (Reduction in Rate Base as per Table 4) times (Return on Rate Base) or ($2.9 million times 9.14 %).
26 This is the effective date for Newfoundland Power of the Accrual Method of accounting for OPEBs for financial reporting purposes pursuant to section 3461 of the CICA Handbook.

The manner in which the Transitional Obligation is recognized as an expense for regulatory purposes is to be determined by the Board. Current accounting guidelines, under U.S. Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*, effectively require the treatment for financial reporting purposes to match the regulatory treatment.[27]

Given the impact on revenue requirement of Newfoundland Power's proposal to adopt the Accrual Method of accounting for OPEBs costs, the Company proposes that the disposition of the Transitional Obligation be addressed at a subsequent hearing to be determined by the Board.

Newfoundland Power's proposals would effectively result in a two stage approach to addressing the Company's OPEBs accounting policy. The first stage would be the adoption of the Accrual Method of accounting on a prospective basis commencing January 1, 2010. The second stage would be addressing, at a later date, the legacy OPEBs costs represented by the Transitional Obligation.

A two stage approach benefits customers by reducing the immediate impacts on revenue requirement and customer rates that would otherwise be associated with the adoption of the Accrual Method of accounting for OPEBs costs for regulatory purposes

3.0 TAX-EFFECTING EMPLOYEE FUTURE BENEFITS EXPENSE

Newfoundland Power proposes to tax-effect employee future benefits expense through the adoption of the asset and liability method of income tax accounting for regulatory purposes commencing in 2010.[28]

3.1 Tax-Effecting Generally

The timing of the recognition of an expense for income tax purposes is determined by federal and provincial tax laws. The timing of the recognition of an expense for financial reporting and regulatory purposes is determined by GAAP or the regulator.

The period in which an expense is recognized for income tax purposes may, therefore, differ from the period in which it is recognized for financial reporting and regulatory purposes. When this happens, the income tax effects of an expense and the expense itself are not recognized in the same period.

To "tax-effect" an expense means to recognize the income tax effects of the expense in the period in which the expense itself is recognized for financial reporting and regulatory purposes.

[27] Prior to 2009, Canadian GAAP contained guidance that effectively permitted the recognition of regulatory assets and liabilities. Effective 2009, the AcSB removed from Canadian GAAP the guidance that permitted recognition of regulatory assets and liabilities. For 2009 and 2010, Canadian regulated utilities effectively rely on U.S. GAAP (particularly, Statement of Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*) which permits recognition of regulatory assets and liabilities on a conceptually similar basis to that allowed under Canadian GAAP prior to 2009. Commencing in 2011, the recognition of regulatory assets and liabilities will be governed by IFRS.

[28] The treatment for regulatory purposes will effectively result in an identical treatment for financial reporting purposes.

This is accomplished through the recognition of future income tax for financial reporting and regulatory purposes.

3.2 Current and Future Income Tax

Current income tax expense (recovery) is the amount of income tax actually paid (recovered) in the current period, i.e., "cash taxes".[29]

Future income tax expense is the reduction in cash taxes in the current period that is attributable to expenses that will be recognized in future periods for financial reporting and regulatory purposes.

Future income tax recovery is the reduction in cash taxes that is expected to occur in future periods that is attributable to expenses recognized in the current period for financial reporting and regulatory purposes.

When an entity's accounting policy for financial reporting and regulatory purposes is to recognize only current income taxes, it is said to follow the "Flow-through Method".

When an entity's accounting policy for financial reporting and regulatory purposes is to recognize both current and future tax, it is said to use the "Asset and Liability Method". In order to tax-effect OPEBs expense an entity would follow the Asset and Liability Method with respect to that expense.

Newfoundland Power's income tax accounting policy for financial reporting and regulatory purposes is a hybrid of these two methods. The Company recognizes future income tax liabilities in connection with: (i) temporary timing differences between depreciation expense and capital cost allowance; and (ii) temporary timing differences between pension funding and expense.[30] It also tax-effects its regulatory reserves, such as the weather normalization reserve. Otherwise, it follows the Flow-through Method.

3.3 Regulatory Standards

Tax-effecting OPEBs partially mitigates the impact on customer rates of adopting the Accrual Method of accounting for OPEBs.

The excess of OPEBs expense determined using the Accrual Method over that determined using the Cash Method is not deductible in determining current income tax expense for the period. Rather, this additional amount of OPEBs expense becomes tax deductible in future years when the insurance premiums and retiring allowances that it represents are actually paid.

By tax-effecting OPEBs, these future income tax impacts are recognized in the same period as the associated expense. This is consistent with the principle of intergenerational equity. To do otherwise would result in one generation of customers bearing the cost and another generation receiving the tax benefits.

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[29] An income tax recovery is effectively a reduction in income tax expense.

[30] The tax effecting of timing differences between pension funding and pension expense was approved by the Board in Order No. P.U. 32 (2007).

Tax-effecting OPEBs expense is accomplished by recognizing a net future income tax recovery and a net future income tax asset in an amount equal to the net reduction in cash taxes that is expected to occur in future periods when the expense effectively becomes tax deductible. This serves to offset a portion of the additional OPEBs expense recognized under the Accrual Method of accounting, thereby reducing revenue requirement.

The immediate result of tax-effecting is a reduction in the impact on customers of a switch from the Cash Method to the Accrual Method of accounting for OPEBs. The long-term impact is to smooth fluctuations in net OPEBs expense and the resultant revenue requirement.

3.4 Impact of Tax-Effecting on Revenue Requirement

Table 6 provides the forecast impacts that tax-effecting OPEBs would have on Newfoundland Power's future income tax recoveries, future income tax asset and rate base for 2010.

Table 6
Tax-Effecting OPEBs
2010 Forecast Future Income Tax and Rate Base Impacts
(millions)

Future Income Tax Asset, Beginning of the Year	$ -
Future Income Tax Recovery[31]	1.7
Future Income Tax Asset, End of the Year[32]	$ 1.7
Increase in Rate Base (Average Future Income Tax Asset)[33]	$ 0.8

The future income tax recovery of $1.7 million shown in Table 6 reduces revenue requirement. The increase in rate base of $0.8 million shown in Table 6 increases revenue requirement. The net impact is a reduction in revenue requirement.

31 Represents the reduction in income tax expense that would be shown on Newfoundland Power's statement of income.
32 Represents the future income tax asset that would be shown on Newfoundland Power's balance sheet.
33 Equals (Future Income Tax Asset, Beginning of the Year plus Future Income Tax Asset, End of the Year) divided by 2.

Table 7 shows the 2010 forecast impact on revenue requirement.

Table 7
Tax-Effecting OPEBs
2010 Forecast Impact on Revenue Requirement
($millions)

Income Tax Recovery	
Future Income Tax Recovery	(1.7)
Tax Effects[34]	(0.8)
Change in Revenue Requirement	(2.5)
Return on Rate Base	
Rate Base Effects	0.1
Tax Effects	-
Change in Revenue Requirement	0.1
Change in Revenue Requirement	(2.4)

Table 7 shows, on a forecast basis, that tax-effecting OPEBs would reduce the impact on customers of the proposed adoption of the Accrual Method of accounting for OPEBs.

4.0 CONCLUSION

In this Application, Newfoundland Power proposes to:

(i) adopt the Accrual Method of accounting for OPEBs costs for regulatory purposes commencing in 2010;
(ii) tax-effect employee future benefits costs related to OPEBs expense for regulatory purposes commencing in 2010; and
(iii) defer consideration of the Transitional Obligation of $46.2 million until a further hearing to be determined by the Board.

[34] Equals 1.7 million future income tax recovery times (the 32% corporate income tax rate divided by (1 minus the 32% income tax rate)).

Table 8 provides the impacts of Newfoundland Power's proposals on 2010 revenue requirement.

Table 8
Forecast Impacts of Proposals
2010 Test Year Revenue Requirement
($millions)

OPEBs Accrual Method[35]	8.0
Tax-Effecting of OPEBs[36]	(2.4)
Increase in Revenue Requirement	5.6

Newfoundland Power's accounting proposals for OPEBs would increase 2010 test year revenue requirement by approximately $5.6 million, or 1.0%.[37]

The adoption of the Accrual Method of accounting for OPEBs expense on a prospective basis will bring Newfoundland Power's OPEBs accounting policy into the mainstream of Canadian regulated utility practice commencing in 2010. It will also align the accounting for OPEBs with that of the Company's defined benefit pension plans and with the accounting practice for OPEBs followed by Hydro. The Accrual Method is consistent with GAAP, the cost of service standard and the principle of intergenerational equity.

Addressing the disposition of the Transitional Obligation of $46.2 million at a subsequent hearing reduces the impact on customer rates that would otherwise be associated with the adoption of the Accrual Method.

Tax-effecting OPEBs expense is consistent with the principles of intergenerational equity and rate stability. As well, tax-effecting OPEBs expense reduces the impact on customers of the proposed adoption of the Accrual Method of accounting for OPEBs costs.

35 From Table 5.
36 From Table 7
37 1.0% customer rate impact equals $5.6 million from Table 8 divided by $568.7 million total customer charges under existing rates from Exhibit 10.

The Surveyed Utilities

Utility	**Regulatory Jurisdiction**
Altalink	Alberta
Atco Electric	Alberta
Atco Gas	Alberta
B.C. Hydro	British Columbia
Enbridge Gas	Ontario
Enersource Hydro	Ontario
FortisAlberta	Alberta
FortisBC	British Columbia
FortisOntario	Ontario
Gaz Metro	Quebec
Hydro One	Ontario
Hydro Ottawa	Ontario
Hydro Quebec	Quebec
Manitoba Hydro	Manitoba
Maritime Electric	Prince Edward Island
New Brunswick Power	New Brunswick
Newfoundland & Labrador Hydro	Newfoundland
Northwest Territories Power Corp.	Northwest Territories
Nova Scotia Power	Nova Scotia
Ontario Power Generation	Ontario
Pacific Northern Gas	British Columbia
Saskatchewan Power	Saskatchewan
Terasen	British Columbia
Toronto Hydro	Ontario
Union Gas	Ontario
Yukon Electrical Company	Yukon
Total Utilities 26	**Total Regulatory Jurisdictions 12**

Actuarial Valuation of OPEBs at December 31, 2008

19 January 2009

Newfoundland Power Inc.

Report on Non-Pension Retirement Benefit Expense for the Fiscal Year Ending December 31, 2008 Under CICA Section 3461

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

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Contents

1

Report Highlights

This report has been prepared by Mercer at the request of Newfoundland Power Inc. This report provides non-pension post retirement expense reporting for financial statements and interested parties pursuant to Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461"), relating to the Non-Pension Post Retirement Benefit Plan.

The Non-Pension Post Retirement Benefit Plan is a defined benefit plan funded on a cash basis by contributions from Newfoundland Power Inc.

Fiscal Year Ending December 31, 2008

The net period benefit cost calculated in accordance with CICA 3461 for the fiscal year ending December 31, 2008, is a charge of $7,722,000.

The employer-paid benefit payments during the fiscal year ending December 31, 2008 were $1,175,000.

The accrued benefit liability as of December 31, 2008 is $41,074,000.

2

Principal Expense and Disclosure Information

A summary of principal expense information, as required for disclosure purposes pursuant to CICA 3461, from the current fiscal year follows.

Components of Net Periodic Benefit Cost[1]	Fiscal Year Ending December 31, 2008	Fiscal Year Ending December 31, 2007
1. Current service cost	$1,384,000	$1,412,000
2. Interest cost	3,901,000	3,698,000
3. Actual return on plan assets	0	0
4. Actuarial loss (gain)	(14,885,000)	(3,383,000)
Costs arising in the period	**($9,600,000)**	**$1,727,000**
Differences between costs arising in the period and costs recognized in the period in respect of:		
▪ Return on plan assets	0	0
▪ Actuarial loss (gain)	15,894,000	4,710,000
▪ Transitional obligation (asset)	1,428,000	1,428,000
Net periodic benefit cost recognized	**$7,722,000**	**$7,865,000**

[1] CICA 3461 requires an analysis of the components of net periodic benefit cost showing separately amounts arising from events in the period, the difference between actual return on plan assets and the expected return on plan assets, other adjustments for deferrals and amortizations of amounts previously deferred, and the change in the valuation allowance if applicable. The actual derivation of the net period benefit cost is set out in the Supplemental Information – Development of Costs section of this report.

Principal Expense Information *(continued)*

Weighted-Average Assumptions for Expense	Fiscal Year Ending December 31, 2008	Fiscal Year Ending December 31, 2007
Discount rate	5.50%	5.25%
Expected long-term rate of return on plan assets	N/A	N/A
Rate of compensation increase	4.00%	4.00%
Initial prescription drug trend rate	6.50%	7.00%
Ultimate prescription drug trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012
Initial semi-private hospital and other medical cost trend rate	4.50%	4.50%
Ultimate semi-private hospital and other medical cost trend rate	4.50%	4.50%
Year ultimate rate reached	N/A	N/A
Initial weighted average health care trend rate	6.05%	6.46%
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2012	2012

Weighted-Average Assumptions for Disclosure	Fiscal Year Ending December 31, 2008	Fiscal Year Ending December 31, 2007
Discount rate	7.50%	5.50%
Expected long-term rate of return on plan assets	N/A	N/A
Rate of compensation increase	4.00%	4.00%
Initial prescription drug trend rate	9.50%	6.50%
Ultimate prescription drug trend rate	4.50%	4.50%
Year ultimate rate reached	2028	2012
Initial semi-private hospital and other medical cost trend rate	5.00%	4.50%
Ultimate semi-private hospital and other medical cost trend rate	5.00%	4.50%
Year ultimate rate reached	N/A	N/A
Initial weighted average health care trend rate	9.33%	6.05%
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2028	2012

Principal Expense Information *(continued)*

Change in Accrued Benefit Obligation	**Fiscal Year Ending December 31, 2008**	**Fiscal Year Ending December 31, 2007**
Accrued benefit obligation at end of prior year	**$70,411,000**	**$69,804,000**
Current service cost	1,384,000	1,412,000
Interest cost	3,901,000	3,698,000
Employees' contributions	0	0
Benefits paid	(1,175,000)	(1,120,000)
Actuarial loss (gain)	(14,885,000)	(3,383,000)
Accrued benefit obligation at end of year	**$59,636,000**	**$70,411,000**

Change in Plan Assets	**Fiscal Year Ending December 31, 2008**	**Fiscal Year Ending December 31, 2007**
Fair value of plan assets at end of prior year	**$0**	**$0**
Estimated employer contributions	(1,175,000)	(1,120,000)
Employees' contributions	0	0
Estimated benefits paid	(1,175,000)	(1,120,000)
Fair value of plan assets at end of year	**$0**	**$0**

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	**Fiscal Year Ending December 31, 2008**	**Fiscal Year Ending December 31, 2007**
Surplus (Deficit) at end of year	**($59,636,000)**	**($70,411,000)**
Employer contributions during period from measurement date to fiscal year end	0	0
Unamortized transitional obligation (asset)	12,285,000	13,713,000
Unamortized past service costs	0	0
Unamortized net actuarial loss (gain)	6,277,000	22,171,000
Accrued benefit asset (liability)	**($41,074,000)**	**($34,527,000)**

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Certification

We have prepared an actuarial valuation of Newfoundland Power Inc.'s benefit obligations for accounting purposes as at January 1, 2005 and extrapolated those results to Janaury 1, 2008. In accordance with our mandate, the purpose of this valuation and extrapolation is to account for the costs of the plan for the fiscal year beginning January 1, 2008 and ending December 31, 2008 in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461").

In addition, we have prepared an updated actuarial valuation of Newfoundland Power Inc.'s benefit obligations for accounting purposes as at December 1, 2008 and extrapolated those results to December 31, 2008. In accordance with our mandate, the purpose of this valuation and extrapolation is to enable the Company to satisfy the disclosure requirements under CICA 3461.

Plan Provisions

The results of the valuations set forth in this report reflect the provisions of the plan as of the date of the valuations as reported to us by Management.

A summary of the plan provisions and the plan amendments are provided in Section 4 of this report.

Data

The valuation producing 2008 disclosure results is based on membership data as at December 1, 2008 provided by Newfoundland Power Inc. The membership data is summarized in Section 2 of this report.

Subsequent Events

After checking with representatives of Newfoundland Power Inc., to our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions in the valuations and determination of net periodic benefit cost are summarized in Section 3 of this report.

Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future valuations and will affect future net periodic benefit cost.

Actuarial computations under CICA 3461 are for purposes of fulfilling employer accounting requirements. Determination for purposes other than meeting employer financial accounting requirements may be significantly different from the results reported herein. Accordingly, additional determinations are needed for other purposes such as adequacy of funding for the ongoing plan or purchase price calculations or plan design costings.

Supplemental Information

The remainder of the report includes information supporting the results presented in the previous sections.

1. **Development of Costs** shows the financial position of the plan and the calculation of the various components of plan costs.

2. **Membership Data** presents and describes the membership data used in the valuations and the validation checks made on the data.

3. **Valuation Methods and Assumptions** describes the methods and assumptions used to value the plan as well as accounting policies used to calculate the net periodic benefit cost.

4. **Summary of Plan Provisions** provides a summary of the benefits, which have been valued for this report.

5. **Employer Certification**

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Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of Section 3461 of the CICA Handbook.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best-estimate assumptions, selected for accounting purposes, in accordance with CICA 3461. These assumptions are in accordance with accepted actuarial practice.

In our opinion,

- The data on which the valuations are based are sufficient and reliable for the purposes of the valuations, and
- The calculations have been made in accordance with the requirements of Section 3461 of the CICA Handbook

This report has been prepared and my opinion given, in accordance with accepted actuarial practice.

Respectfully submitted,

Kerry Worgan
Fellow of Society of Actuaries
Fellow of Canadian Institute of Actuaries

January 19, 2009

Date

Appendix A

Development of Costs

This Appendix shows the liabilities for plan benefits and the calculation of the various components of plan costs.

Financial Position of the Plan

		January 1, 2008	January 1, 2007
1.	Accrued benefit obligation		
	a. Retirees and survivors	($38,626,000)	($38,317,000)
	b. Active fully eligible members	(4,570,000)	(4,483,000)
	c. Active not fully eligible members	(27,215,000)	(27,004,000)
	d. Total (a. + b. + c.)	**($70,411,000)**	**($69,804,000)**
2.	Fair value of plan assets	0	0
3.	**Surplus (Deficit) (1(d) + 2.)**	**($70,411,000)**	**($69,804,000)**
4.	Employer contributions after measurement date	0	0
5.	Unamortized transitional obligation (asset)	13,713,000	15,141,000
6.	Unamortized past service costs	0	0
7.	Unamortized net actuarial loss (gain)	22,171,000	26,881,000
8.	**Accrued benefit asset (liability) (3.+4.+5.+6.+7.)**	**($34,527,000)**	**($27,782,000)**

Net Periodic Pension Cost

		Fiscal Year Ending December 31, 2008	Fiscal Year Ending December 31, 2007
1.	Current service cost	$1,384,000	$1,412,000
2.	Interest cost	3,901,000	3,698,000
3.	Expected return on plan assets	0	0
4.	Amortizations		
	a. Transitional obligation (asset)	1,428,000	1,428,000
	b. Past service costs	0	0
	c. Net actuarial loss (gain)	1,009,000	1,347,000
5.	**Net periodic benefit cost**	**$7,722,000**	**$7,865,000**

Components of these calculations are developed below:

Interest Cost

		Fiscal Year Ending December 31, 2008	Fiscal Year Ending December 31, 2007
1.	Accrued benefit obligation	$70,411,000	$69,804,000
2.	a. Current Service Cost	1,384,000	1,412,000
	b. Weighted for timing	1,384,000	1,412,000
3.	a. Plan amendment	0	0
	b. Weighted for timing	0	0
4.	a. Expected distributions	(1,732,000)	(1,545,000)
	b. Weighted for timing	(866,000)	(773,000)
5.	Average accrued benefit obligation (1. + 2(b) + 3(b) – 4(b))	$70,929,000	$70,443,000
6.	Discount rate	5.50%	5.25%
7.	**Interest cost (5. x 6.)**	**$3,901,000**	**$3,698,000**

Amortization Amounts

	January 1, 2008	January 1, 2007
1. Transitional Obligation (Asset)		
a.) Unamortized transitional obligation (asset) as of beginning of year	**$13,713,000**	**$15,141,000**
b.) Years Remaining	**9.6**	**10.6**
c.) Amortization amount	**$1,428,000**	**$1,428,000**
2. Past Service Costs		
a.) Unamortized past service costs as of beginning of year	**$0**	**$0**
b.) Years Remaining	**n/a**	**n/a**
c.) Amortization amount	**$0**	**$0**
3. Unamortized (gain)/loss subject to amortization as of beginning of year		
a.) Unamortized net actuarial loss (gain) [from A.7]	**$22,171,000**	**$26,881,000**
b.) Accrued benefit obligation [from A.1(d)]	**70,411,000**	**69,804,000**
c.) 10% of accrued benefit obligation b.	**7,041,000**	**6,980,000**
d.) Unamortized net actuarial loss (gain) subject to amortization [excess of a. over c., if any]	**15,130,000**	**19,901,000**
e.) Expected average remaining service	**15**	**15**
f.) Amortization amount (d. ÷ e.)	**$1,009,000**	**$1,327,000**

Sensitivity to Change in Health Care Cost Trend Rates

	Medical	Accrued Benefit Obligation as of December 31, 2008	Service Cost for 2008	Interest Cost for 2008	Aggregate of Service Cost and Interest Cost for 2008
1.	Valuation trend	$59,636,000	$1,384,000	$3,901,000	$5,285,000
2.	Valuation trend + 1%	67,955,000	1,693,000	4,605,000	6,298,000
3.	**Difference (2. – 1.)**	**$8,319,000**	**$309,000**	**$704,000**	**$1,013,000**
4.	Valuation trend – 1%	52,929,000	1,127,000	3,350,000	4,477,000
5.	**Difference (4. – 1.)**	**($6,707,000)**	**($257,000)**	**($551,000)**	**($808,000)**

Analysis of Other Liability Loss (Gain)

	Gains and Losses Due to:	Due to Remeasurement as of December 31, 2008
1.	Change in demographics	($4,243,000)
2.	Change in claims costs	(9,391,000)
3.	Change in aging	(14,000)
4.	Change in medical trend	18,178,000
5.	Change in discount rate	(20,888,000)
6.	Change in mortality assumption	2,030,000
7.	Actual benefit payments differing from expected	(557,000)
	Total	**($14,885,000)**

Appendix B

Membership Data

The actuarial valuation is based on membership data as at December 1, 2008, provided by Newfoundland Power Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), earnings, and service. The results of these tests were satisfactory. Our testing did not include verifying the data to member source records.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

Analysis of Membership Data

Active Employees	**December 1, 2008**	**January 1, 2005**
Executive		
Number	5	5
Average earnings	$237,720	$207,200
Average years of service	12.5 years	10.6 years
Average age	46.3	43.5
Management		
Number	260	236
Average earnings	$71,736	$66,820
Average years of service	21.1 years	19.8 years
Average age	46.8	44.9
Union		

Active Employees	**December 1, 2008**	**January 1, 2005**
Number	356	336
Average earnings	$54,586	$48,539
Average years of service	20.5 years	19.4 years
Average age	47.8	45.9
Total		
Number	621	577
Average earnings	$63,241	$57,391
Average years of service	20.7 years	19.5 years
Average age	47.4	45.5

	December 1, 2008	**January 1, 2005**
Retirees		
Number	507	540
Average age	67.3	64.9
Spouses		
Number	406	464
Average age	64.0	61.6
Widows		
Number	131	113
Average age	74.0	73.3

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

Reconciliation of Membership

	Executives	**Management**	**Union**	**Retirees & Surviving Spouses**	**Total**
Total at January 1, 2005	**5**	**236**	**336**	**653**	**1,230**
Adjustments	-	-	-	5	5
New entrants	3	37	60	-	100
Transfers To/(From) Executive Plan:	-	-	-	-	-
Transfers To/(From) Management Plan:	-	-	(14)	-	(14)
Transfers To/(From) Union Plan:	-	14	-	-	14
Terminations / Deaths	(3)	(21)	(15)	(77)	(116)
Retirements	-	(6)	(11)	17	-
Surviving spouses	-	-	-	40	40
Total at December 1, 2008	**5**	**260**	**356**	**638**	**1,259**

The distribution of the active members by age and completed years of service as at December 1, 2008 is summarized as follows:

Distribution of Active Members
By Age Group and Completed Years of Service as at December 1, 2008

	Years of Completed Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30+**	**Total**
Under 20								0
20 - 24	8							8
25 - 29	24							24
30 - 34	19	10	2					31
35 - 39	19	16	10	5				50
40 - 44	14	17	16	24	31	1		103
45 - 49	3	6	7	18	34	38	4	110
50 - 54	5	5	6	15	20	33	103	187
55 - 59	1	1	1	7	8	6	69	93
60 - 64			1	2	3	1	8	15
65+								0
Total	93	55	43	71	96	79	184	621

The distribution of the retirees and surviving spouses by age as at December 1, 2008 is summarized as follows:

Distribution of Retirees
By Age Group as at December 1, 2008

Age	Retirees	Spouses	Widows	Total
Under 50	-	3	4	7
50 - 54	12	36	6	54
55 - 59	77	99	7	183
60 - 64	146	99	5	250
65 - 69	100	81	19	200
70 - 74	91	53	23	167
75-79	42	24	30	96
80-84	26	10	19	55
85-89	10	1	13	24
90+	3	-	5	8
Total	507	406	131	1,044

Appendix C

Valuation Methods and Assumptions

Cost Method

Accrued benefit obligations shown in this report are computed using the Projected Benefit Method Pro Rated on Service, as defined in CICA 3461. The objective under this method is to expense each member's benefits under the plan taking into consideration projections of benefit costs to and during retirement. Under the Projected Benefit Method Pro Rated on Services, an equal portion of the total estimated future benefit is attributed to each year of service.

For retirees, spouses and surviving spouses, the accrued benefit obligation (ABO) is the present value of all future projected benefits as at the beginning of the fiscal year.

For each active member, a "full eligibility" date is determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement.

Full eligibility is the earlier of age 55 with 2 years of service or age plus service of 85 points

For active members who have reached "full eligibility", the ABO is the present value of all future projected benefits as at the beginning of the fiscal year. For these members, the service cost is zero.

For active members who have not yet reached "full eligibility", the ABO is the present value of all future projected benefits as at the beginning of the fiscal year, multiplied by the ratio of service at the valuation date to projected service at "full eligibility". For these members, the current service cost is the present value of benefits deemed to accrue in the fiscal year, and is determined as the present value of all future projected benefits divided by the projected service at "full eligibility".

The accrued benefit obligation is the actuarial present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **accrued benefit obligation** is the sum of the individual accrued benefit obligations for all members under the plan.

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.

Accounting Policies

Management applied the Recommendations of Section 3461 of the CICA Handbook prospectively and elected to amortize the transitional (asset)/obligation on a linear basis from January 1, 2005 over the average remaining service period of active members expected to receive benefits under the plan 15.0 years.

Obligations are attributed to the period beginning on the member's date of hire and ending on the date of reaching first full eligibility for benefits.

Summary of Assumptions

The following assumptions were used in valuing the benefit obligations under the plan.

Measurement date	January 1	
Discount rate	▪ 5.50% per annum for the December 31, 2007 funded status and Fiscal 2008 net periodic benefit cost determination ▪ 7.50% per annum for the December 31, 2008 funded status and estimated Fiscal 2009 net periodic benefit cost determination	
Salary increases	4.00% per annum	
Health care cost trend rates	Semi-private Hospital	5.00% per annum
	Prescription drugs	9.50% per annum in 2008 grading down to 4.50% per annum in and after 2028
	Other medical	5.00% per annum
	Vision care	0.00% per annum
	Health premium	5.00% per annum
Life Premium Increases	None	
Mortality	Static 1994 Group Annuity Table Rates at sample ages are shown below (per 1000 members):	

Age	Male	Female
20	0.51	0.28
30	0.80	0.35
40	1.07	0.71
50	2.58	1.43
60	7.98	4.44
70	23.73	13.73
80	62.03	39.40
90	152.93	116.27

Withdrawal

50% of Ontario Light to Age 39

Rates at sample ages are shown below:

Age	Male	Female
20	9.0%	9.0%
25	5.0%	5.0%
30	2.8%	2.8%
35	1.6%	1.6%
39+	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

Retirement Age	One year after the later of the date of attainment of age 60 and completion of age plus service of 95 points, but not later than age 65.
Marital status	For active members, 80% are assumed to be married at retirement with males assumed to be 3 years older than their female spouses.

2008 per covered member claim costs (at age 65) with administration and taxes			Pre 65	Post 65
	Semi-private hospital		$18.30	$5.72
	Prescription drugs		$1,480.34	$1,244.67
	Vision care		$76.65	$36.61
	Other medical		$276.85	$137.28
	Total		$1,852.14	$1,424.28
Employer Cost Sharing of Premium	Under 65 – 50%			
	Over 65 – 0%			
2008 Employee Annual Premium			Single	Family
	Health		$942.96	$2,232.72
	Group life (per $1,000)		$3.77	N/A
	Dependent life (per $1,000)		$24.60	N/A
Increases in utilization by age	**Attained Age**	**Semi-Private Hospital**	**Prescription Drug**	**Other Medical**
	55	7.0%	3.8%	-0.2%
	60	7.8%	2.8%	-0.6%
	65	10.0%	2.1%	-0.5%
	70	9.5%	1.1%	1.2%
	75	9.3%	0.5%	1.7%
	80	8.2%	-0.2%	2.2%
	85	6.8%	-0.3%	2.3%
Administrative expenses as a percentage of paid claims	Medical	10.00%		
	Life insurance	10.00%		
Taxes	4.00% of claims and administrative expenses for all medical and life benefits.			
Participation	100% of members are assumed to participate in the retiree health plan.			

Claims Cost Development

The per covered member claim costs used in the December 1, 2008 valuation and extrapolated for purposes of determining the liabilities as at December 31, 2008 were based on the actual retiree and dependent claims information for the 2 year period, November 1, 2006 to October 31, 2008, increased with assumed inflation to 2009. This claims experience was collected and analysed separately for Hospital, Prescription Drug, Vision Care, and Other Medical benefits.

A description of the process used to set the "2008 Per Covered Person Claim Costs (at age 65) with Administration and Taxes" shown in Section 3 D) is as follows:

- For each calendar year of claims, a cost per covered member was developed by dividing the total annual claims by the total number of eligible retirees, and dependents covered during the year.
- This cost per person has been adjusted to the cost per covered member at age 65 based on the actual individual ages of the covered members using the "Increases in Utilization by Age" assumptions shown in Section 3 D).
- These costs have been increased to include the cost of insurance company administrative expenses and provincial taxes charged on the claims.
- The costs are then trended forward from the claims experience year to the midpoint of the valuation year of June 1, 2009.
- As indicated, this analysis was performed for the 2 year period November 1, 2006 to October 31, 2008. The assumed cost per covered member for the December 1, 2008 valuation was based on a weighted average of the costs for the two years, as follows:

Percentage Contribution to Valuation Assumed 2008 Claim Cost	
Nov 2006 – Oct 2007 claims experience	50.0%
Nov 2007 – Oct 2008 claims experience	50.0%
Total	**100.0%**

NFLD Power

Retiree Claims Cost Analysis - Pre 65

	Nov 1, 2007 - Oct 31, 2008	Nov 1, 2006 - Oct 31, 2007
Actual NFLD Power retirees' paid claims (before administration costs and taxes)		
Hospital	$4,250	$3,740
Drug	430,487	390,839
Vision Care	28,765	30,181
Other Medical	109,186	91,550
Total	**$572,688**	**$516,310**
Number of NFLD Power retirees, spouses and surviving spouses		
• Eligible for medical benefits	428	428
• Eligible for drug benefits	428	428
Per covered member costs		
Hospital	$9 93	$8 74
Drug	1,005 81	913 18
Vision Care	67 21	70 52
Other Medical	255 11	213 90
Total	**$1,338.06**	**$1,206.33**
Trend to May 01, 2008		
Hospital	1 00	1 05
Drug	1 00	1 10
Vision Care	1 00	1 00
Other Medical	1 00	1.05
2007 per covered member costs		
Hospital	$9 93	$9 13
Drug	1,005 81	1.004 49
Vision Care	67 21	70 52
Other Medical	255 11	223 53
Total	**$1,338.06**	**$1,307.67**
Weighting	**50%**	**50%**
Trend to May 01, 2009		
Hospital	1 05	
Drug	1 10	
Vision Care	1 00	
Other Medical	1 05	
2008 per member costs		
Hospital	$9 96	
Drug	1,105 67	
Vision Care	68 86	
Other Medical	250 09	
Total	**$1,434.58**	
Adjustment factors to convert 2008 per member costs into age 65 per covered member costs		
Hospital	1 6065	
Drug	1 1703	
Vision Care	0.9730	
Other Medical	0.9677	
Average drug offset assumption at age 65	**0%**	
Per covered member age 65 claims costs (2008 per member costs x adjustment factors)		
Hospital	$16 00	
Drug - incorporating 0% drug offset	$1,294 00	
Vision Care	$67.00	
Other Medical	$242 00	
Total	**$1,619.00**	
Administration costs and taxes		
• Administration costs	10 00%	of claims
• Premium and sales taxes	4 00%	of claims
Per covered member age 65 claims costs with administration costs and taxes		
Hospital	$18 30	
Drug - incorporating 0% drug offset	$1,480 34	
Vision Care	$76 65	
Other Medical	$276 85	
Total	**$1,852.14**	
Benefit adjustment factors due to differences in plan provisions		
Hospital	1 00	
Drug	1 00	
Vision Care	1 00	
Other Medical	1 00	

NFLD Power 2008 per covered member age 65 claims costs with administration costs and taxes

	Total
Hospital	$18 30
Drug - incorporating 0% drug offset	$1,480 34
Vision Care	$76 65
Other Medical	$276 85
Total	**$1,852.14**

<u>NFLD Power</u>

Retiree Claims Cost Analysis - Post 65

	Nov 1, 2007 - Oct 31, 2008	Nov 1, 2006 - Oct 31, 2007
Actual NFLD Power retirees' paid claims (before administration costs and taxes)		
Hospital	$16,252	$10,780
Drug	643,200	580,259
Vision Care	18,547	17,607
Other Medical	94,866	79,800
Total	**$772,865**	**$688,447**
Number of NFLD Power retirees, spouses and surviving spouses		
• Eligible for medical benefits	610	610
• Eligible for drug benefits	610	610
Per covered member costs		
Hospital	$26.64	$17.67
Drug	1,054.43	951.24
Vision Care	30.40	28.86
Other Medical	155.52	130.82
Total	**$1,266.99**	**$1,128.60**
Trend to May 01, 2008		
Hospital	1.00	1.05
Drug	1.00	1.10
Vision Care	1.00	1.00
Other Medical	1.00	1.05
2007 per covered member costs		
Hospital	$26.64	$18.47
Drug	1,054.43	1,046.37
Vision Care	30.40	28.86
Other Medical	155.52	136.71
Total	**$1,266.99**	**$1,230.41**
Weighting	**50%**	**50%**
Trend to May 01, 2009		
Hospital	1.05	
Drug	1.10	
Vision Care	1.00	
Other Medical	1.05	
2008 per member costs		
Hospital	$23.57	
Drug	1,155.44	
Vision Care	29.63	
Other Medical	152.69	
Total	**$1,361.33**	
Adjustment factors to convert 2008 per member costs into age 65 per covered member costs		
Hospital	0.2121	
Drug	0.9416	
Vision Care	1.0798	
Other Medical	0.7859	
Average drug offset assumption at age 65	**0%**	
Per covered member age 65 claims costs (2008 per member costs x adjustment factors)		
Hospital	$5.00	
Drug - incorporating 0% drug offset	$1,088.00	
Vision Care	$32.00	
Other Medical	$120.00	
Total	**$1,245.00**	
Administration costs and taxes		
• Administration costs	10.00%	of claims
• Premium and sales taxes	4.00%	of claims
Per covered member age 65 claims costs with administration costs and taxes		
Hospital	$5.72	
Drug - incorporating 0% drug offset	$1,244.67	
Vision Care	$36.61	
Other Medical	$137.28	
Total	**$1,424.28**	
Benefit adjustment factors due to differences in plan provisions		
Hospital	1.00	
Drug	1.00	
Vision Care	1.00	
Other Medical	1.00	
NFLD Power 2008 per covered member age 65 claims costs with administration costs and taxes		
	Total	
Hospital	$5.72	
Drug - incorporating 0% drug offset	$1,244.67	
Vision Care	$36.61	
Other Medical	$137.28	
Total	**$1,424.28**	

Appendix D

Summary of Plan Provisions

This Appendix provides a summary of the benefits which have been valued in this report.

Life Insurance

Executives	4 times salary, maximum of $2,000,000, reduction to 25% at age 65, with $10,000 maximum.
Management & Union	3 times salary, maximum of $2,000,000, reduction to 25% at age 65, with $10,000 maximum.
Basic AD&D	Matches life benefit, terminates at age 65.
Dependent Life	$10,000/spouse and $5,000/dependent child.

Medical Benefits

	Retiree < Age 65	**Retiree Age 65 and > ***
Available Coverage	Single or family	Single or family
Hospital	Semi-private 100% Unlimited days No deductible	Semi-private 80% Unlimited days No deductible
Drugs	Prescription drugs (generic basis) 80%	Prescription drugs (generic basis) 80%

	Retiree < Age 65	**Retiree Age 65 and > ***
	No per prescription deductible	No per prescription deductible
	No dispensing fee cap	No dispensing fee cap
	Managed Care Formulary	Managed Care Formulary
	Coverage for life	Coverage for life
Vision	100%	100%
	$200/24 months	$150/36 months
Major Medical	100% supplies and appliances	80% supplies and appliances
Hearing Aids	$600/year/3 years	$600/year/3 years
Private Duty Nursing	100%	80%
	$10,000/year	$5,000/illness
Paramedical	100%	80%
	$250 max per benefit, except physiotherapy $500/year	$250 max per benefit, except physiotherapy $500/year
Out-of-Canada	100%	100%
	Limited to overall plan maximum	Limited to overall plan maximum

** - Combined annual maximum of $5,000 applies to the hospital, extended health, vision and drug benefit for any one person in any one calendar year*

Retirement Allowance

Upon retirement, employees with 10 or more years of service receive an allowance of:

- (1 x Basic Weekly Pay) x number of years employed; to a maximum retirement allowance of 20 weeks of basic pay

Provincial Programs

The government of Newfoundland covers all residents aged 65 or older who receive the Guaranteed Income Supplement under the Senior Citizen's Drug subsidy plan. We have assumed that all retirees and future retirees of Newfoundland will be ineligible for the GIS supplement and hence no retiree will be covered by the provincial program

Appendix E

Employer Certification

With respect to the Report on Non-Pension Post Retirement Benefit Expense for the Fiscal Year Ending December 31, 2008 Under CICA Section 3461 of the Newfoundland Power Inc.'s non-pension post retirement benefit plan, I hereby certify that, to the best of my knowledge and belief:

- The membership data supplied to the actuary provides a complete and accurate description of all persons who are entitled to benefits under the terms of the plans for service up to the date of the valuation
- A copy of the plan documents and of all amendments made up to December 1, 2008 were supplied to the actuary;
- All substantive commitments (as defined under CICA 3461) have been communicated to the actuary;
- Accounting policies as adopted by the Company are those described in this report;
- The actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- The Management's best-estimate assumptions for purposes of the valuations of the plan and the extrapolation of the financial position of the plan as of the fiscal year end December 31, 2008 are those described in this report; and
- All events subsequent to the valuation that may have an impact on the results of the valuation or a future valuation have been communicated to the actuary.

May 2009
Date

Jocelyn Perry
Signed

Jocelyn Perry
Name

VP Finance & CFO
Title

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Consulting. Outsourcing. Investments.

Newfoundland Power Inc.
Customer, Energy and Demand Forecast

May 2009

Table of Contents

1.0 INTRODUCTION

The Customer, Energy and Demand forecast, which is prepared annually, forms the foundation of Newfoundland Power's planning process. The forecast is a key input in developing estimates of capital expenditures required to ensure the electrical system can meet the increasing demands associated with both customer and energy sales growth. The forecast also directly impacts the forecast of both revenue from electrical sales and the Company's single largest expenditure, purchased power. These items are key components of the Company's financial planning process.

2.0 FORECAST METHODOLOGY

Newfoundland Power provides electrical service to three distinct categories of customers: domestic; general service; and, street and area lighting. In 2008, domestic accounted for 60% of total energy sales while general service and street and area lighting represent 39% and 1%, respectively.

The domestic category, Rate 1.1, primarily refers to residential dwellings such as single detached homes, single attached homes, apartments and mobile homes. This category also includes non-residential services such as cottages, personal use garages and other metered services that qualify for the domestic rate category. Residential customers use electricity primarily for space and water heating, and the operation of miscellaneous appliances and lighting. In this category a customer/average use methodology is employed where customer growth is primarily based on the housing starts while average use is forecast using an end-use/econometric model that includes the market share for electric space heating, personal disposable income and the marginal price of electricity in the current and previous year.

The general service category primarily refers to commercial, institutional and industrial customers. Unlike the domestic category which represents a homogenous group of customers, the general service category represents a very diverse group whose activities include, trade, finance, real estate, public administration, health, education, commercial services, transportation, manufacturing, mining, fishing, forestry and construction. These customers provide goods and services to the local market as well as for export. In 2008, approximately 85% of energy sales in this category were to customers in the service producing sector of the economy while only 15% were in the goods producing sector.

From a forecasting perspective the general service category is divided into small general service which includes Rate 2.1 0 - 10 kW and Rate 2.2 10 – 100 kW (110 kVA) and large general service which includes Rate 2.3 110 kVA (100 kW) – 1000 kVA and Rate 2.4 1000 kVA and Over. In the small general service category a customer/average use methodology is employed where the number of customers is primarily based on the number of domestic customers while average use is forecast using an econometric model that includes the Gross Domestic Product ("GDP") for the service sector per small general service customers and the average price of electricity in the current year.

Given the relatively small number of customers in the large general service category, an informed opinion methodology is employed and energy sales are forecast on an individual customer basis.

Street and area lighting energy sales are primarily related to the number of fixtures required to meet the lighting needs of both municipalities and unincorporated communities. At the end of 2008 approximately 57,000 fixtures were installed with high pressure sodium fixtures accounting for 88% of these fixtures and mercury vapour accounting for the remainder. Given the nature of this category, an end use forecasting methodology is employed. The street and area lighting sales forecast is determined by multiplying the forecast quantity of fixtures by the amount of electricity consumed for each fixture type and wattage.

Total energy sales are calculated by adding domestic, general service, and street and area lighting sales. Company use, system losses and wheeled energy are then added to total energy sales to obtain total produced, purchased and wheeled. Company use includes all electricity consumed in facilities owned by Newfoundland Power and used in the delivery of service to customers. System losses refer to energy that is lost during the transmission and distribution of energy between the source of supply and delivery to customers. Wheeled information is provided by Newfoundland and Labrador Hydro.

Purchased energy is calculated by subtracting normal hydro production ("Normal Production") from the forecast of total produced and purchased. Each year Normal Production is adjusted to reflect plant availability and any modifications to plants that may impact production.

Newfoundland Power's native peak is determined using a load factor based methodology. The load factor used in the calculation is the average of 15 years of normalized annual load factors. Native peak is calculated by applying the average load factor to total produced and purchased power. This peak is adjusted to reflect the impact of load curtailment by Newfoundland Power customers and at company owned facilities. Purchased power demand is calculated by subtracting the generation credit from native peak.

3.0 KEY FORECAST ASSUMPTIONS

The forecasting process relies on a wide range of information related to the economy, energy prices, conservation and demand management activities, and other resource based developments within Newfoundland Power's service territory.

3.1 Economic Outlook

While the Company monitors forecasts from various banks and financial institutions, the Conference Board of Canada is the Company's primary provider of economic information. The economic assumptions used in preparing the customer, energy and demand forecasts are based on the Conference Board of Canada, *Provincial Outlook Spring 2009, Economic Forecast,* dated April 21, 2009. A table summarizing the key economic indicators contained in this forecast for 2009 and 2010 is shown in Appendix A. A copy of the Conference Board of Canada's economic forecast is enclosed as Attachment A.

Since 1996, large resource based projects such as Hibernia, Terra Nova, White Rose and Voisey's Bay have reshaped the economy of Newfoundland and Labrador. The mining sector has experienced average annual growth of 18% per year and in 2008 accounted for approximately 30% of the total economy. Consequently, over the past 10 years the Newfoundland and Labrador economy has increased at an average annual growth of 4.6% per year, the highest growth of any Province. Despite the moratorium on cod, the fishing sector contributed to economic growth with increased landings of both crab and shrimp. The development of these resource based projects has positively impacted other key economic indicators such as personal income, unemployment rates and service sector growth. On the downside problems in the newsprint industry forced the closure of the mill in Stephenville in 2005 negatively impacting the manufacturing sector.

Economic performance will continue to be driven by large resource based projects. In 2008 economic performance was constrained by lower oil production with the mining sector contracting by 6.1%. With the major offshore oil fields reaching peak production in 2007 it is expected that production will continue to fall until the satellite oil fields come online.

Newfoundland and Labrador will not escape the impact of the global recession. With commodity prices plummeting from record levels, metal mining companies such as Wabush Mines, the Iron Ore Company of Canada and the Voisey's Bay nickel mine have cut production and announced layoffs. In March 2009 the newsprint mill at Grand Falls – Windsor operated by AbitibiBowaters closed resulting in the direct loss of 755 jobs. The operator of the remaining newsprint operation in the province at Corner Brook has also announced production cuts. As expected, declining production at offshore oil fields will significantly impact economic growth in 2009. On a positive note the investment outlook is promising. Construction of a US$2.2 billion nickel processing facility at Long Harbour is scheduled to start in the spring of 2009, the continued development of the offshore satellite oil fields and government infrastructure spending will boost economic growth.

With the global recession expected to ease in the latter part of 2009 the outlook for the Newfoundland and Labrador economy in 2010 is expected to improve. Higher commodity prices will result in a recovery in mineral production and manufacturing will rebound as the global economy improves. Construction on the nickel processing facility at Long Harbour will continue and oil production levels will stabilize as the first of the offshore satellite fields start production. Based on these assumptions GDP is forecast to decrease 5.0% in 2009 and increase by 1.0% in 2010.

Given Newfoundland Power's customer base, energy sales growth is primarily influenced by the domestic economy. More specifically, growth in the service sector, changes in employment levels, personal income, energy prices and population demographics in the Company's service territory are more determinative of sales growth than resource industry production levels.

Economic growth will not be uniform across Newfoundland Power's service territory. In the Northeast Avalon, growth will continue to be strong principally due to activities related to the offshore oil industry. In contrast much of rural Newfoundland and Labrador is expected to continue the trend of economic stagnation.

3.2 Energy Prices Outlook

Changes in energy prices have a direct impact on energy sales growth through the inclusion of price elasticity effects in the various models. Overall, analysis of customer response to changes in the price of electricity is relatively inelastic. That is to say a 1% change in the price of electricity will result in a change in energy sales of less than 1%. The current model indicated that a 1% increase in the price of electricity will result in a 0.25% decrease in energy sales. The model also indicates the response will vary depending on the time frame and rate category. In addition, changes in oil prices can impact the market share of electricity in the competitive space heating market.

The energy sales forecast is impacted by changes in the price of electricity during the past two years as well as forecast changes in the price of electricity. Electricity price forecasts are developed based on information available internally and provided by Newfoundland and Labrador Hydro. The annual review of the rate stabilization account resulted in an increase in the price of electricity of 5.9% on July 1, 2008. The forecast assumes that the annual review of the rate stabilization account will result in a decrease in the price of electricity of 6.6% on July 1, 2009. As proposed in Newfoundland Power's application, a 6.1% increase in current customer rates (i.e. effective July 1, 2008) effective January 1, 2010 has been included in the energy sales forecast under proposed rates.

Due to a collapse in the world price of oil in late 2008, furnace oil prices are forecast to decline significantly in 2009. With the world price of oil forecast to partially recover from its collapse, furnace oil prices are forecast to increase in 2010. This projection is consistent with the fuel forecast used in the calculation of the rate stabilization account.

3.3 Conservation and Demand Management Impacts

The energy sales forecast includes the impact of conservation and demand management. The adjustments to the forecast are consistent with the Five-Year Energy Conservation Plan: 2008 – 2013. In the domestic category the forecast includes the impact of the Insulation Program, Thermostat Program and the Energy Star Windows Program while the general service category has been adjusted for the Lighting Rebate Program.

3.4 Other Inputs

Information from a number of other sources is also used in preparing the forecast. Each year Newfoundland Power surveys approximately 150 customers representing approximately 600 accounts requesting information with respect to future load requirements. This information along with information gathered from Newfoundland Power's regional operations, the St. John's Board of Trade, various other trade organizations, and the provincial and federal governments is also incorporated into the large general service forecast. In addition, information from Canada Mortgage and Housing with respect to housing starts is combined with information received from the Conference Board of Canada in preparing the domestic customer forecast.

4.0 CUSTOMER AND ENERGY FORECAST

Appendix B shows the customer and energy forecasts for the 2009 - 2010 period under both existing and proposed rates. Under both scenarios the total number of customers is forecast to increase by 1.3% in 2009 and 1.1% in 2010. Energy sales under existing rates are forecast to increase by 1.8% in 2009 and 1.7% in 2010. Energy sales under proposed rates are forecast to increase by 1.8% in 2009 and 1.0% in 2010.

Domestic customer growth is largely a result of housing starts. The Conference Board of Canada forecasts housing starts of 2,719 units in 2009 and 1,947 in 2010 while Canada Mortgage and Housing is projecting 2,675 units in 2009 and 2,775 units in 2010. Using an average of these forecasts the number of domestic customers is forecast to grow by 1.3% in 2009 and 1.1% in 2010.

Domestic electricity consumption is a function of the major end uses in the home, such as space heating, water heating, lighting, and major appliances. In addition, changes in energy prices and income have an impact on electricity consumption. Using proposed rates the average use of energy is forecast to increase by 0.9% in 2009 and decrease by 0.2% in 2010.

The combined impact of increased numbers of customers and changes in average use will result in growth in domestic energy sales under proposed rates of 2.4% in 2009 and 0.9% in 2010.

In the small general service rate classes 2.1 and 2.2, customer and energy sales growth are dependent on growth in the service-producing sector of the GDP and changes in the price of electricity. In the large general service rate classes 2.3 and 2.4, energy sales are also influenced by changes in the service-producing sector of the GDP. However, in the large general service category, energy sales are mainly determined by changes in the load of larger customers in the goods-producing sector. Information obtained from specific customers is incorporated into forecasts for rate classes 2.3 and 2.4.

Overall, the number of general service customers is forecast to grow by 2.1% in 2009 and 0.6% in 2010. Under proposed rates the volume of General Service energy sales is forecast to grow by 1.0% in 2009 and 1.1% in 2010.

In the street and area lighting class, the number of customers is forecast to grow by 1.0% in 2009 and 0.9% in 2010 while the volume of energy sales is forecast to decline by 0.3% in 2009 and 1.1% in 2010. The decrease in street and area lighting energy sales is the net result of the connection of new fixtures and the project to replace all mercury vapour fixtures with energy efficient high pressure sodium fixtures over a three year period starting 2009.

Produced and purchased is the sum of total energy sales, company use and system losses. The forecast of company use is based on historical energy usage and information gathered from each of Newfoundland Power’s operating areas with respect to the operation of these facilities. System losses are based on historical information and are forecast to be approximately 5.4% of total produced and purchased.

5.0 PURCHASED ENERGY AND DEMAND FORECAST

Purchased energy is calculated by subtracting Newfoundland Power's Normal Production from produced and purchased. Newfoundland Power's Normal Production is based on the Water Management Study – Hydrology Update prepared by SGE Acres Limited in 2005. This study recommended a Normal Production of 419.6 GWh.

Each year, Normal Production is adjusted to reflect plant availability and any modifications to plants that may impact production. In 2008 the Normal Production was increased by 6.2 GWh to reflect increased production resulting from the modifications to the Rattling Brook Hydro plant. A review of the operating results of the Rattling Brook Hydro plant for 2008 indicated that the actual increase in Normal Production was 8.3 GWh. Therefore, the Normal Production was increased to 427.9 GWh.

For 2009, a review of the project to replace the penstock at the Rocky Pond Hydro Plant indicated that plant availability would be affected and spillage would occur. As a result, the Company adjusted the Normal Production downward by 2.0 GWh in 2009 to reflect the lost production. Therefore, the Normal Production is 425.9 GWh in 2009.

In 2010 the Normal Production has been increased by 0.9 GWh to reflect increased production resulting from the modifications to the Rose Blanche Hydro plant. Projects scheduled for 2010 are not expected to impact plant availability, therefore, the Normal Production will be 428.8 GWh in 2010.

Newfoundland Power's forecast of native peak demand is determined by applying the average weather adjusted load factor to the forecast of produced and purchased energy. The peak demand is then adjusted to reflect the impact of load curtailment by Newfoundland Power customers and company owned facilities. Newfoundland Power's purchased demand is then derived by subtracting the generation credit approved by the Public Utilities Board.

A copy of the Purchased Energy and Demand Forecast is contained in Appendix C.

6.0 FORECAST ACCURACY

The energy sales forecasts and actual weather adjusted energy sales for the past 10 years are shown in Appendix D. During this period, differences from forecast have ranged from a high of 2.8% to a low of 0.1%. In 6 of the past 10 years, differences from forecast were 1% or less. Further, the analysis of differences indicates that 50% of the time the actual was higher than forecast and vice versa.

Newfoundland Power Inc.

Key Economic Indicators[1]
2007 - 2010F

(millions of dollars)

				Forecast			
Indicator	**2007**	**2008**	**Change From 2007**	**2009**	**Change From 2008**	**2010**	**Change From 2009**
Gross Domestic Product ($ 2002)							
Goods Producing Industries	8,066	7,729	-4.2%	6,647	-14.0%	6,664	0.3%
Service Producing Industries	9,477	9,740	2.8%	9,911	1.8%	10,072	1.6%
Total of All Industries	18,011	17,920	-0.5%	17,019	-5.0%	17,197	1.0%
Consumer Price Index (2002=100)	111.1	114.3	2.9%	114.9	0.5%	118.0	2.7%
Personal Disposable Income ($ 2002)	10,495	11,145	6.2%	11,295	1.3%	11,335	0.4%
Unemployment Rate (%)	13.6%	13.3%		14.9%		15.7%	
Housing Starts - Units	2,649	3,261	23.1%	2,719	-16.6%	1,947	-28.4%
Canadian GDP Deflator (2002=100)	117.8	122.9	4.4%	119.8	-2.5%	121.9	1.8%
Canada Mortgage and Housing Corporation[2]							
Housing Starts - Units	2,649	3,261	23.1%	2,675	-18.0%	2,775	3.7%

[1] Conference Board of Canada, Provincial Outlook Spring 2009, Economic Forecast, Dated: April 21, 2009.
[2] Canada Mortgage and Housing Corporation, Housing Market Outlook, First Quarter, 2009.

Newfoundland Power Inc.

Customer & Energy Forecast
2007 - 2010F

		Actual			Existing				Proposed			
		2007	2008	Percentage Change	2009	Percentage Change	2010	Percentage Change	2009	Percentage Change	2010	Percentage Change
Customers												
Domestic	1.1	201,045	204,204	1.6%	206,767	1.3%	209,074	1.1%	206,767	1.3%	209,074	1.1%
General Service												
0-10 kW	2.1	11,826	11,920	0.8%	12,174	2.1%	12,115	-0.5%	12,174	2.1%	12,115	-0.5%
10-100 kW (110 kVA)	2.2	8,509	8,626	1.4%	8,809	2.1%	8,991	2.1%	8,809	2.1%	8,991	2.1%
110 kVA (100 kW) - 1000 kVA	2.3	1,035	1,061	2.5%	1,077	1.5%	1,088	1.0%	1,077	1.5%	1,088	1.0%
1000 kVA and Over	2.4	66	65	-1.5%	69	6.2%	67	-2.9%	69	6.2%	67	-2.9%
Total General Service		21,436	21,672	1.1%	22,129	2.1%	22,261	0.6%	22,129	2.1%	22,261	0.6%
Street and Area Lighting	4.1	9,781	9,902	1.2%	10,005	1.0%	10,096	0.9%	10,005	1.0%	10,096	0.9%
Total Customers		232,262	235,778	1.5%	238,901	1.3%	241,431	1.1%	238,901	1.3%	241,431	1.1%
Energy Sales (GWh)												
Domestic	1.1	3,044.4	3,130.3	2.8%	3,204.6	2.4%	3,273.0	2.1%	3,204.6	2.4%	3,234.7	0.9%
General Service												
0-10 kW	2.1	90.9	88.8	-2.3%	89.7	1.0%	89.9	0.2%	89.7	1.0%	89.6	-0.1%
10-100 kW (110 kVA)	2.2	629.2	641.8	2.0%	647.4	0.9%	657.6	1.6%	647.4	0.9%	655.5	1.3%
110 kVA (100 kW) - 1000 kVA	2.3	864.5	878.5	1.6%	889.5	1.3%	901.8	1.4%	889.5	1.3%	901.8	1.4%
1000 kVA and Over	2.4	427.6	432.3	1.1%	435.7	0.8%	437.3	0.4%	435.7	0.8%	437.3	0.4%
Total General Service		2,012.2	2,041.4	1.5%	2,062.3	1.0%	2,086.6	1.2%	2,062.3	1.0%	2,084.2	1.1%
Street and Area Lighting	4.1	36.2	36.5	0.8%	36.4	-0.3%	36.0	-1.1%	36.4	-0.3%	36.0	-1.1%
Total Energy Sales		5,092.8	5,208.2	2.3%	5,303.3	1.8%	5,395.6	1.7%	5,303.3	1.8%	5,354.9	1.0%
Company Use		11.8	11.7	-0.8%	11.8	0.9%	11.8	0.0%	11.8	0.9%	11.8	0.0%
Losses		289.9	293.9	1.4%	303.4	3.2%	308.7	1.7%	303.4	3.2%	306.3	1.0%
Produced & Purchased		5,394.5	5,513.8	2.2%	5,618.5	1.9%	5,716.1	1.7%	5,618.5	1.9%	5,673.0	1.0%
Wheeled		70.4	77.2	9.7%	74.8	-3.1%	70.2	-6.1%	74.8	-3.1%	70.2	-6.1%
Total System Energy		5,464.9	5,591.0	2.3%	5,693.3	1.8%	5,786.3	1.6%	5,693.3	1.8%	5,743.2	0.9%

Newfoundland Power Inc.

Purchased Energy & Demand Forecast
2009 - 2010F

	Produced Purchased & Wheeled	Total Wheeled Energy	Total Curtailed Demand	Total Produced & Purchased (NP Native Peak)			NP Produced		Total Purchased	
			(1)		(2)	(3) Load	(4)	(5) Credit		(6)
Year	**GWH**	**GWH**	**MW**	**GWH**	**MW**	**Factor**	**GWH**	**MW**	**GWH**	**MW**
Existing										
2009	5,693.3	74.8	10.9	5,618.5	1,262.69	50.36%	425.9	117.93	5,192.6	1,144.76
2010	5,786.3	70.2	10.9	5,716.1	1,284.82	50.36%	428.8	117.93	5,287.3	1,166.89
Proposed										
2009	5,693.3	74.8	10.9	5,618.5	1,262.69	50.36%	425.9	117.93	5,192.6	1,144.76
2010	5,743.2	70.2	10.9	5,673.0	1,275.05	50.36%	428.8	117.93	5,244.2	1,157.12

Notes:

1. Based on historical performance of participants plus curtailment of company owned facilities.
2. Native peak is the maximim demand forecast to be served by Newfoundland Power. The 2009 native peak reflects the forecast for the winter period of December 2009 to March 2010.
3. Load Factor is based on an average of 15 year historical (normalized) load factors.
4. Average water year for the forecast period is 427.9 GWh adjusted for plant availability and efficiency improvements.
5. Assumes a generation credit of 117.93 MW.
6. The purchased demand for 2009 reflects the purchased demand from Newfoundland and Labrador Hydro for the winter period of December 2009 to to March 2010 and represents Newfoundland Power's forecast billing demand for 2010.

Newfoundland Power Inc.

Comparison of Forecast Energy Sales To Weather Adjusted Actual Sales[1]

	Forecast Sales[2] (GWh)	Weather Adjusted Actual Sales (GWh)	Difference (GWh)	Difference (%)
1999	4,516.4	4,499.7	-16.7	-0.4
2000	4,558.5	4,554.8	-3.7	-0.1
2001	4,592.3	4,666.7	74.4	1.6
2002	4,652.0	4,764.9	112.9	2.4
2003	4,852.2	4,882.0	29.8	0.6
2004	4,927.0	4,978.6	51.6	1.0
2005	5,010.1	5,004.0	-6.1	-0.1
2006	5,136.9	4,995.1	-141.8	-2.8
2007	5,023.1	5,092.8	69.7	1.4
2008	5,215.1	5,208.2	-6.9	-0.1

Notes:

[1] Amounts for 1999 - 2005 are reported on a billed basis while amounts for 2006 - 2008 are reported on a calendar basis.

[2] The forecast sales figures are from the annual forecasts prepared in the previous year and were part of the Capital Budget presentations made to the Board in those years. The 1999, 2003, 2004 and 2008 forecasts were the basis for the revenue requirement determinations presented as part of the Company's General Rate Applications in 1998, 2003 and 2007, respectively.

Conference Board of Canada
Provincial Outlook Spring 2009
Economic Forecast
Dated: April 21, 2009

The Conference Board of Canada
Insights You Can Count On

Provincial Outlook Spring 2009

Economic Forecast

ECONOMIC PERFORMANCE AND TRENDS

The Conference Board of Canada
Insights You Can Count On

Provincial Outlook Spring 2009: Economic Forecast
by *The Conference Board of Canada*

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Preface

The *Provincial Outlook Spring 2009* was prepared by Marie-Christine Bernard, Associate Director, under the general direction of Paul Darby, Deputy Chief Economist.

The report examines the economic outlook for the provinces, including gross domestic product (GDP), output by industry and labour market conditions. At the end of the report, there is a forecast for Canadian economic indicators and a comparison of GDP by province and industry.

The Provincial Outlook is updated quarterly using the Conference Board's large econometric model of the provincial economies.

The publication can be accessed on-line at www.e-library.ca and for clients subscribing to e-Data at www.conferenceboard.ca/edata.htm.
For more information, please contact our information specialist at 613-526-3280 or 1-866-711-2262 or e-mail contactcboc@conferenceboard.ca.

Contents

Marie-Christine Bernard

Ontario and Alberta Hardest Hit by Global Recession

HIGHLIGHTS

- Canada is in the midst of recession. A decline in commodity prices and exports, coupled with soft domestic demand, will lead to a 1.7 per cent drop in real GDP in 2009.
- Despite major construction projects, Newfoundland and Labrador's real GDP growth will nosedive this year as falling productive capacity in the offshore petroleum industry limits growth prospects going forward.
- The economic focus has shifted to the Atlantic region where, for the first time in more than 25 years, net interprovincial migration will be positive.
- In Quebec, the current recession will not be as devastating as were the major downturns of the early 1980s and 1990–91.
- Massive government fiscal stimulus will not be enough to pull Ontario out of the recession brought on by the crash in the auto industry and other important sectors.
- Manitoba will manage to remain in positive territory and will be one of the few provinces to post a budgetary fiscal surplus in 2009–10.
- The outlook for Saskatchewan has been downgraded. A larger-than-expected drop in global fertilizer demand has led to significant cutbacks in potash production in the first half of the year.
- The Alberta and British Columbia economies are suffering. The construction boom is a thing of the past in the two western-most provinces, and a recovery is not in the cards until next year.

NATIONAL OVERVIEW

Despite drastic intervention, the U.S. government, Treasury, and Federal Reserve have not yet succeeded in overcoming the crisis in the struggling financial sector. The U.S. economy continues to bleed jobs at an accelerating pace, doing little to rekindle consumer confidence; and the full brunt of a decline in U.S. household spending is now coming to bear on the global economy. Recent indicators suggest that 2009 may see the first contraction in global trade in over 60 years, resulting in a multiplier effect that could bring even the strongest economies to their knees. While growth remains positive in key developing nations such as China and India, these gains will not be enough to offset declines in the United States, much of Western Europe, and Japan.

Even with its relatively healthy banking sector and strong fiscal position, Canada now finds itself in recession. According to Statistics Canada, the economy contracted in the fourth quarter of 2008 at an annual rate of 3.4 per cent, the most significant quarterly decline since the 1990–91 recession. Moreover, the outlook for the first half of 2009 is dismal. Demand for exports, consumer goods, housing, and private investment are expected to show declines. The only bright spot comes from the loosening of the public purse strings, as governments spend heavily in a bid to stimulate the economy back to health. (Strong public spending, however, will come at a cost of sizable near-term deficits.) We are now forecasting that Canada's real gross domestic product will contract by 1.7 per cent in 2009. While Canada's economy is still searching for footing, the U.S. recession is much further along; and there are signs that our southern neighbour's economy is starting to form a bottom on a few fronts. Residential construction, for example, is at levels well below demographic requirements. By some estimates, so are vehicle sales. Both U.S. residential construction and auto sales are heavily weighted components for our export sector. Yet, while we may have reached bottom on these fronts, the timing of a significant recovery remains a critical risk to the outlook. This forecast assumes that the U.S. economy will crawl back into growth over the latter half of 2009 before picking up steam in 2010. Nonetheless, even the modest growth expected in the United States will help to stabilize our own economy and push Canadian real GDP growth up by 2.5 per cent in 2010.

Canada's economy is certainly not immune to the global collapse in trade. Real export volumes are forecast to fall by nearly 11 per cent this year on the heels of a 4.7 per cent decline in 2008. However, price effects are serving to aggravate the effects of falling trade. This year, oil prices are expected to average less than half their 2008 average of US$100 per barrel, and commodity prices on the whole are forecast to decline by 29 per cent! At the same time, the cost of imports has risen sharply due to the sharp depreciation in the loonie over the fourth quarter of last year. Overall, the nominal trade balance is forecast to drop by a phenomenal $65 billion in 2009—an amount equivalent to 4.2 per cent of nominal GDP.

While it was the drop in equity markets and concerns about a global economic downturn that first affected business confidence in Canada, the ensuing sharp drop in nominal trade revenues and profits has completely paralyzed business investment. Revenues plummeted over the second half of 2008, and the result is that oil sands development and conventional drilling are being held back by shrinking budgets. At the same time, non-energy construction will be down because of the completion of a number of major commercial and office-building projects and the lack of appetite for starting anything new. Moreover, tax incentives will do little to motivate struggling manufacturers to invest in retooling or new machinery. Total real business investment is forecast to drop by a record[1] 14 per cent this year, and only a modest recovery is forecast for 2010.

In addition to a sharp drop in capital investment intensions, Canadian businesses are also cutting back on payrolls. Employment dropped sharply at the start of 2009, largely in the construction and manufacturing sectors; and more prudent hiring is resulting in a growing share of part-time employment at the expense of full-time jobs. Similar to business confidence, household confidence was also first affected by falling equity values. However, the reality of job losses and weak employment prospects soon sank in, leading consumers to cut back sharply on spending late in 2008 and early this year. Despite a soft recovery in spending forecast for the second half of 2009, real consumer spending will remain essentially flat this year.

It currently looks as though government spending will be the only bright spot in the forecast, as provincial and federal governments commit to large stimulus packages and large deficits. In its January budget, the federal government committed about $12 billion over two years to new infrastructure spending. This spending should be matched by equivalent funds at the provincial level. Ontario's March 2009 budget did exactly that, injecting hefty sums into infrastructure while also providing strong growth in program spending. Like the federal budget, Ontario's brings a large price tag—a $14.1-billion deficit for the current fiscal year.

PROVINCIAL OVERVIEW

The global recession, bankruptcy fears in the auto and pulp and paper industries and other important sectors, and depressed commodity prices are crippling the provincial economies. Ontario and Alberta will suffer the most. Other provinces will endure setbacks—but not to the same extent. With the exception of the public sector, Ontario is facing severe contractions in all sectors. Alberta will be hurt by the lethargy in the energy industry. British Columbia is also facing its worst performance since 1982, with major declines expected in the forestry, manufacturing, and construction sectors. In Newfoundland and Labrador, overall real GDP will plunge this year. The drop is due mainly to a falloff in oil production as productive capacity declines at the province's three main fields (Hibernia, Terra Nova, and White Rose).

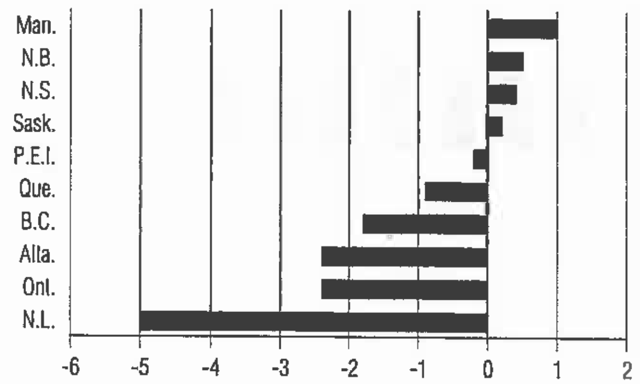
Saskatchewan's economic prospects have been downgraded due to faltering global demand for fertilizers. The province will still manage to eke out a small positive real GDP gain this year. Manitoba will lead the way with 1 per cent growth, and two of the Maritime provinces—Nova Scotia and New Brunswick—will record modest economic growth.

The overall weakness will slowly dissipate in the second half of 2009. Boosted by federal fiscal stimulus and a turnaround south of the border, all provinces will bounce back in 2010.

The global economic turmoil is not hitting Quebec nearly as hard as Ontario. While labour markets have been bleeding jobs in Quebec, the domestic economy will suffer only a minor decline. With no interruption in the provincial infrastructure program, public investment will continue to support economic growth in Quebec over the next two years. Overall real GDP at basic prices will fall 0.9 per cent in 2009. (See charts 1 and 2.) Ontario is at the mercy of U.S. consumer demand, which continues to fall. The Ontario economy is expected to fall by 2.4 per cent this year. The province's battered manufacturing sector is already downsizing at an accelerated pace, and it will face another major output contraction this year. At best, the sector will stabilize next year. With the auto industry in shambles, exports are forecast to decline by 55 per cent over 2008–09! And the prospect of bankruptcy is challenging the industry even more. While the auto industry grabs most of the headlines, other sectors in Ontario are also reeling. Real business investment is forecast to plunge by 13.8 per cent this year. Major fiscal stimulus will, however, help the province over the next two years. Increased public program spending and capital investment will add 1.2 percentage points to bottom line growth in 2009. The downturn will gradually give way to a recovery. Central Canada will greatly benefit from the federal measures to jump-start the economy. Overall, real GDP growth is expected to reach 1.8 per cent in Quebec and 2.5 per cent in Ontario in 2010. (That forecast is dependent, however, on a turnaround in the U.S. economy.)

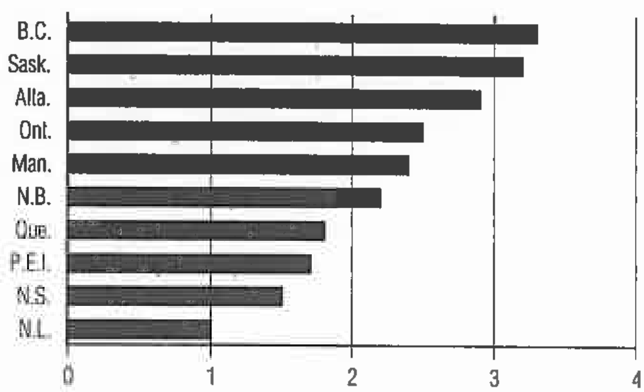
With the lure of Western Canada's economic opportunities abating, the tide of migration from Atlantic Canada to the West has turned. Job losses in Atlantic Canada have been relatively modest compared with the national average, retail spending is still sound, and the housing market has not showed signs of fatigue like it has in other regions. For the first time in more than 25 years, net interprovincial migration will be positive for Atlantic Canada this year. Relative to other provinces, prospects are more encouraging. New Brunswick will avoid recession by shoring up public spending on infrastructure and by reducing households' fiscal burden. Several of the province's industrial sectors will nonetheless

Chart 1
Real GDP by Province, 2009
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Real GDP by Province, 2010
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

continue to struggle, in line with the U.S recession. The fishing, forestry, and manufacturing industries will be hard hit. Still, New Brunswick's economy is forecast to gain 0.5 per cent in 2009. A better 2.2 per cent performance is forecast for 2010 as some preliminary design and engineering work gets under way on construction of a second gasoline refinery. Similarly, Nova Scotia will also benefit from fiscal initiatives aimed at encouraging economic activity. The development of the Deep Panuke natural gas offshore project will also stimulate the economy. All in all, real GDP growth will reach 0.4 per cent in Nova Scotia this year. Despite a recovery in the national economy, the province will record only moderate 1.5 per cent growth next year, as no large construction projects are anticipated. Once a source of strength, the offshore petroleum industry in Nova Scotia has peaked, and falling natural gas production will dampen economic growth until 2011 when the Deep Panuke project becomes operational. For Newfoundland and Labrador, a large contraction in forestry, mining, and manufacturing will push real GDP down by 5 per cent this year. Outside these sectors, Newfoundland and Labrador has favourable prospects, especially in the construction industry. A modest 1 per cent rebound is forecast next year. Prince Edward Island will hold its own this year as its economy contracts by a modest 0.2 per cent this year. Economic growth of 1.7 per cent is forecast next year as the province gears up for the massive development of wind power energy on the Island.

Manitoba will be one of the few provinces to enjoy positive economic growth, a balanced provincial budget, and decent industrial activity. The province is not immune to the global weakness, and it is facing a number of risks. Nonetheless, its economy is expected to grow by 1 per cent in 2009 and 2.4 per cent in 2010. Saskatchewan's economy easily outpaced all other provincial economies last year. The strength in the province was not isolated to just the primary and industrial sectors—the domestic economy was also thriving. However, retail sales have been slowing down since the beginning of the year, as have other parts of the domestic economy. The Saskatchewan success story is not over, but an 18 per cent drop in potash production will take a bite out of economic growth this year. Despite massive personal income tax cuts and a sizable infrastructure program, real GDP growth will tumble to 0.2 per cent in 2009. Saskatchewan will get a big boost once potash production resumes, and economic growth of 3.2 per cent is forecast for next year.

Alberta's economy is headed for its worst year since 1986. The energy sector collapsed late last year, and it will only start to recover in 2010 when oil prices improve and construction costs moderate. It is estimated that half of the oil sands capital expenditures initially planned for this year—about $20 billion—have been deferred. The good news is that this investment has not been cancelled permanently, and longer-term prospects are very good for the energy industry once oil prices return to a more profitable level. Winter drilling activity was very disappointing and will also be a major weakness for the province until energy prices (in particular, natural gas prices) strengthen. With the energy sector going from boom to bust in just a few months, it is not surprising that development in other sectors also took a beating. Office, industrial, and commercial vacancy rates are on the rise, especially in the suburban areas. All in all, Alberta's economy is expected to decline by 2.4 per cent this year before returning to a more normal 2.9 per cent pace of growth in 2010.

British Columbia will not see any improvement before early next year when the 2010 Olympic Winter games will give a much-needed boost to the province's tourism, recreational, and retail industries. But the Olympics are not the only factor supporting a major rebound. After sinking by 1.8 per cent in 2009, the province is forecast to lead all other provinces with 3.3 per cent overall real GDP gains in 2010. After several years of hardship, the forestry and manufacturing industries will reach bottom this year and will then provide a positive contribution to growth over the near term.

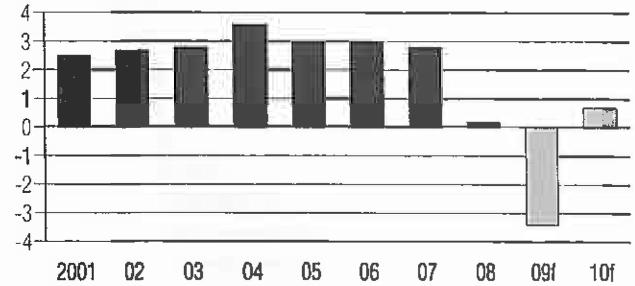
U.S. ECONOMY

Officially, the U.S. recession has now been dragging on for over a year.[2] The correction in real estate markets has been even longer. Home sales and residential construction peaked in mid-to-late 2005 and have been trending down steadily since. Nonetheless, signs of a turnaround are still scarce. The massive spending undertaken by the Federal Reserve and Treasury will eventually help turn the tide and lead to a recovery in the U.S. economy toward the end of this year. However, it will take time for the stimulus to work. In the meantime, most of the data coming out of the economy have been grim. The current outlook calls for real GDP to decline by 2.5 per cent in 2009 before rebounding somewhat and expanding by 2.1 per cent in 2010.

While there are some glimmers of hope that financial and equity markets have hit bottom, the job market has now become the epicentre of the U.S. economic crisis. A mind-numbing 5 million jobs have disappeared since employment peaked at the end of 2007. Some 3.3 million jobs evaporated between last November and March alone. At its current level of 8.5 per cent, the unemployment rate is the highest it has been in a quarter-century. Unfortunately, leading job market indicators—including unemployment insurance claims, hours worked, and temporary help postings—point to further job losses over the near term.

The combination of tumbling labour markets and difficulties encountered in obtaining loans has led consumers to purchase far fewer homes and cars. In fact, the last time U.S. vehicle sales were this low was when the economy was in the grips of the severe recession of the early 1980s. Car sales will likely not improve significantly until the fates of GM and Chrysler are determined and auto loan leases become more available. Sales of new and existing homes have also plunged to close to half the levels attained during the heights of the speculative housing bubble in 2005–06. They would be even lower if not for rising foreclosure sales that account for around two-thirds of sales in California and Florida. Overall, American household spending is forecast to drop by 3.4 per cent in 2009—a phenomenal decline in comparison with what we've seen in previous post-Second World War recessions. (See Chart 3.)

Chart 3
Phenomenal Drop in Spending
(real U.S. consumption expenditures, percentage change)



f = forecast
Sources: The Conference Board of Canada; U.S. Bureau of Economic Analysis (BEA).

The hope is that the policy steps implemented over the past few months will stabilize the economy and improve confidence. In fact, the fiscal policy response has been unprecedented. Congress has passed close to $800 billion in tax cuts and spending increases, while the Obama administration has delivered plans to help homeowners facing foreclosure. The Federal Reserve has been printing money to purchase securities, lending money to investors to buy troubled securities, and providing loans and asset guarantees to struggling financial institutions. These initiatives should help. As well, the aid to state and local governments and increased benefits to unemployed workers included in the stimulus will provide relief in job markets this spring and summer. The administration's housing plans should lead to a refinancing boom in the months ahead.

MONETARY POLICY

In the first quarter of 2009, central banks and national governments around the world continued their efforts to ensure an orderly resolution to the financial market crisis and mitigate the impact of financial market turmoil on the broader economy. These efforts appear to have stabilized the situation and staunched the bleeding. However, efforts to revive the economy through monetary stimulus have, thus far, been hampered by the defensive posture taken by market participants and have had only limited success.

Key central banks have lowered their interest rates dramatically since September 2008. In December, the U.S. Federal Reserve made its last interest rate move by lowering the federal funds rate target range to between zero and 0.25 per cent. That move was largely a foregone conclusion as the Fed's daily open market operations had been hard pressed to keep the effective federal funds rate above 0.25 per cent. The European Central Bank and the Bank of England, which had been behind the interest rate reduction curve in 2008, have lowered interest rates by 275 and 450 basis points, respectively, since September and now have interest rates pegged at historical lows. Closer to home, the Bank of Canada has lowered interest rates substantially since September, bringing its key overnight rate to 0.25 per cent.

In an environment of such low interest rates, the question now arises as to how central banks might add additional stimulus to the economy. While this question is most pressing in the U.S. (where there is no room left to lower interest rates further), key central banks throughout the world are weighing their options. At this point most of these central banks have indicated that they will be engaging, or are prepared to engage, in quantitative or credit easing—a process through which the central bank creates money by purchasing securities from banks. (See box "What is Quantitative Easing?") The U.S. Federal Reserve and the Bank of England have already announced definitive plans for such operations.

What Is Quantitative Easing?

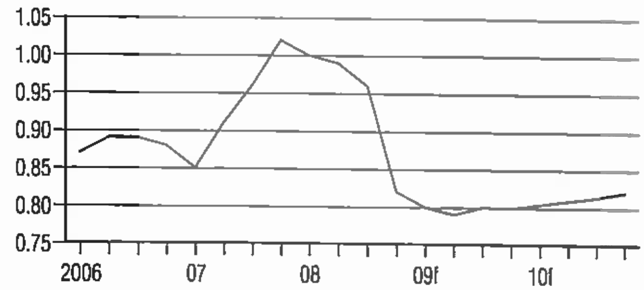
With interest rates at or near record lows, many central banks are turning to quantitative easing as a means of stimulating economies back to health. Under quantitative easing, central banks essentially print money. The money is then used to buy up assets on the market—mostly government bonds, but also asset-backed securities and corporate bonds. The goal is to provide a major infusion of money into the banking system. As well, the central bank is likely to weight its buying toward longer-term bonds, a practice that sends the price of such bonds higher and yields lower. This in turn leads to lower interest rates on mortgages and other longer-term loans.

Over the past two years, central banks have made unprecedented efforts to provide liquidity to the financial system and have lowered interest rates precipitously. With the additional monetary stimulus provided by quantitative and credit easing, central banks face the prospect of significant monetary-policy-induced inflationary pressures as the world economy begins to emerge from recession. Thus, central banks need to be mindful that they may have to unwind their interest rate reductions and reverse their quantitative/credit easing rapidly in order to prevent inflation from taking hold.

Looking forward, the Bank of Canada has little latitude to reduce the bank rate further. Thus, the Bank is likely to forego additional interest rate cuts in favour of a quantitative/credit-easing approach, which might free up some of the liquidity it has already pumped into the system. By the end of 2009, the Bank is expected to begin unwinding some of its stimulus as it seeks to get ahead of the inflation curve. Despite these proactive moves, it is likely that the Bank will have to briefly elevate the bank rate above the neutral 5 per cent level beginning in 2011 to ensure that undesirably high inflation does not gain a foothold.

After taking a nosedive in the last part of 2008, the Canadian dollar is expected to stabilize in 2009. (See Chart 4.) Signs of this have been evident in the relative stability of the loonie during the first quarter. The stability came despite a narrowing of the Canada–U.S. interest rate spread, heightened expectations that the Bank of Canada might provide additional monetary stimulus to the economy through quantitative or credit easing, and relatively modest advances in oil prices. On balance, the Canadian dollar is expected to remain near its current levels through much of the year. Consequently, the loonie will see its first annual decline since 2002. That decline is anticipated to be short-lived, as the loonie is expected to make modest but steady gains throughout the remainder of the forecast horizon.

Chart 4
Less Volatility for the Canadian Dollar
(U.S./Canada exchange rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

FISCAL POLICY

The global economy is expected to shrink this year, and governments around the world have opened the floodgates to economic stimulus in an attempt to turn the tide. The situation is no different in Canada where the federal government released an expensive stimulus package designed to kick-start the economy and restore confidence. Including all measures, the stimulus package is worth roughly 1.5 per cent of real GDP in the current fiscal year (which began on April 1) and 1.1 per cent in 2010–11. This stimulus package will drive direct program spending up by a whopping 13.1 per cent in fiscal year 2009–10—the fastest rate on record. (Comparable data go back to 1983.) The stimulus also includes tax cuts—$10.5 billion over the next two years at the federal level. At the same time, nominal GDP—the widest measure of the federal government tax base—is now expected to contract by 4.1 per cent in 2009. Together, the drop in nominal GDP and the tax cuts will result in total federal government revenues falling by 4.8 per cent in fiscal year 2009–10. Consequently, the federal government now expects to run a cumulative deficit of $76.5 billion over the next three fiscal years, and it is not expected to balance its books until 2013. The string of deficits will erase 10 years of debt payback, drive the federal debt up to $542.4 billion, and push debt-servicing costs up by $9.7 billion per year within three years.

Provincial governments rely on the very same personal and corporate income tax bases, and they are also facing significant cuts in revenues. Moreover, the problem is compounded by the direct effect that the drop in commodity prices will have on royalty revenues. The steady climb in commodity prices boosted royalty revenues to $21.6 billion in 2008, more than double their 2002 level. However, in 2009, the collapse in commodity prices is expected to remove $9.2 billion from royalty revenues while corporate income tax revenues will decline by an additional $5.2 billion. Dealing with the sharp and rapid revenue losses will be difficult for provincial governments, as they will now have to come up with an additional $8.9 billion in infrastructure-matching requirements over the next two fiscal years. The fallout from the global recession will leave provincial governments as a whole with a $34-billion deficit in 2009 (national accounts basis), down from a $400-million surplus in 2008. Although the economic recovery forecast over the medium term will cut the collective deficit in half by 2012, it will not suffice on its own to bring provincial governments back to balanced budgets. Consequently, provincial governments will struggle to rein in spending and perhaps be forced to raise taxes following the recovery in 2010.

Marie-Christine Bernard

La récession mondiale éprouve l'Ontario et l'Alberta plus que les autres

FAITS SAILLANTS

- Malgré divers projets de construction de grande envergure, le PIB réel de Terre-Neuve-et-Labrador dégringolera cette année.
- Le pôle économique est maintenant dans la région de l'Atlantique où, pour la première fois en plus de 25 ans, la migration interprovinciale nette retrouvera des valeurs positives.
- Au Québec, les effets de la récession actuelle ne seront pas aussi dévastateurs que ceux des grands ralentissements du début des années 80 et de 1990-1991.
- Les mesures de relance budgétaire annoncées par les gouvernements ne seront pas suffisantes pour sortir l'Ontario de la récession.
- Le Manitoba réussira à se maintenir en territoire positif et sera l'une des rares provinces à afficher un excédent budgétaire pour l'exercice 2009-2010.
- Les prévisions pour la Saskatchewan ont été revues à la baisse. Le recul plus marqué que prévu de la demande mondiale d'engrais fertilisants a entraîné des baisses importantes de la production de potasse au premier semestre de l'année.
- Les économies de l'Alberta et de la Colombie-Britannique battent de l'aile. Le boum de la construction dans ces deux provinces les plus à l'ouest est maintenant chose du passé, et on n'entrevoit pas de reprise avant l'année prochaine.

LA SCÈNE NATIONALE

En dépit de leur intervention draconienne, le gouvernement, la Réserve fédérale et le Trésor américains n'ont pas encore réussi à débloquer les marchés financiers. L'économie américaine continue de subir des pertes massives d'emplois à un rythme accéléré, ce qui n'aide pas à raviver la confiance des consommateurs. De plus, tout l'effet de la baisse des dépenses de consommation des ménages américains pèse maintenant sur l'économie mondiale. Les indicateurs récents portent à croire que, en 2009, le commerce mondial pourrait connaître sa première contraction en plus de 60 ans et l'effet multiplicateur risque de secouer même les économies les plus fortes. La croissance demeure positive dans certains pays en développement importants, comme la Chine et l'Inde, mais ces gains ne suffiront pas à neutraliser les déclins observés aux États-Unis, dans une grande partie de l'Europe de l'Ouest et au Japon.

Même avec un secteur bancaire relativement sain et une bonne situation budgétaire, l'économie du Canada est aussi frappée par la récession. Selon Statistique Canada, l'économie s'est contractée de 3,4 p. 100 (au taux annuel) au quatrième trimestre de 2008, ce qui constitue le déclin trimestriel le plus important depuis la récession de 1990-1991. De plus, les prévisions pour le premier semestre de 2009 sont sombres. La demande dans les secteurs des exportations, des biens de consommation et du logement, et l'investissement privé devraient baisser. Le seul point positif est le fait que les gouvernements délient les cordons de leur bourse afin de stimuler et de rétablir l'économie. (Cependant, les importantes dépenses publiques auront un prix : des déficits considérables à court terme.) Nous prévoyons maintenant une diminution de 1,7 p. 100 du produit intérieur brut (PIB) réel du Canada en 2009. Pendant que l'économie canadienne tente encore de se positionner, la récession est beaucoup plus avancée aux États-Unis et certains signes indiquent que quelques secteurs de l'économie de notre voisin du Sud touchent le fond du baril. Par exemple, la construction résidentielle est à des niveaux bien inférieurs aux besoins démographiques. Selon certaines estimations, il en est de même pour les ventes d'automobiles. Tant la construction résidentielle que les ventes d'automobiles aux États-Unis sont des composantes qui pèsent lourdement sur nos exportations. Pourtant, même si ces secteurs ont touché le fond, le moment d'une reprise appréciable demeure crucial pour nos prévisions. Selon le Conference Board, l'économie américaine recommencera à croître lentement pendant le second semestre de 2009, avant de se renforcer en 2010. Même cette modeste croissance anticipée aux États-Unis contribuera à stabiliser l'économie du Canada et poussera la croissance de son PIB réel à 2,5 p. 100 en 2010.

L'économie du Canada n'est certainement pas immunisée contre l'effondrement mondial du commerce. Les volumes des exportations réelles devraient chuter de presque 11 p. 100 cette année, à la suite d'un recul de 4,7 p. 100 en 2008. De plus, les effets des prix aggravent les conséquences de la chute des exportations. Cette année, on prévoit que le prix moyen du pétrole sera inférieur à la moitié de sa moyenne (de 100 $US le baril) enregistrée en 2008, et que les prix des produits de base dégringoleront de 29 p. 100! En même temps, les prix des importations se sont envolés à cause de la forte dépréciation du huard au quatrième trimestre de l'an dernier. Dans l'ensemble, on prévoit une diminution phénoménale de la balance commerciale nominale — de 65 milliards de dollars en 2009 — un montant équivalant à 4,2 p. 100 du PIB nominal.

Alors que la confiance des entrepreneurs canadiens a d'abord été ébranlée par le recul des marchés des actions et leur inquiétude face à la crise économique mondiale, la chute des recettes et des bénéfices commerciaux nominaux qui a suivi a complètement paralysé leurs activités d'investissement. Les recettes ont plongé pendant le second semestre de 2008 et des budgets fortement réduits bloquent les projets d'exploitation des sables bitumineux et de forage conventionnel. En même temps, l'activité de la construction non associée au secteur énergétique baissera, en raison de l'achèvement d'un certain nombre de grands projets de construction d'édifices à bureaux et de bâtiments commerciaux, et du manque de motivation pour entreprendre tout nouveau projet. De plus, les stimulants fiscaux ne convaincront pas les fabricants, déjà aux prises avec des difficultés, d'investir dans le réoutillage ou l'achat de nouvelles machines. L'investissement privé réel total devrait enregistrer une baisse record[1] de 14 p. 100 cette année et ne connaître qu'une modeste reprise en 2010.

En plus de réduire considérablement leurs projets de dépense en immobilisations, les entreprises canadiennes réduisent aussi leur masse salariale. L'emploi a chuté brusquement au début de 2009, en grande partie dans les secteurs de la construction et de la fabrication; et la prudence accrue manifestée dans l'embauche fait augmenter la proportion d'emplois à temps partiel, au détriment des emplois à temps plein. Comme la confiance des entreprises, celle des ménages a aussi été ébranlée par la baisse des valeurs nettes réelles. Cependant, les consommateurs ont finalement pris conscience des pertes et des faibles perspectives d'emplois, ce qui les a incités à restreindre considérablement leurs dépenses en 2008 et au début de cette année. En dépit d'une faible reprise anticipée au second semestre de 2009, les dépenses de consommation réelles n'afficheront pratiquement aucune croissance cette année.

Il semble que les dépenses publiques soient le seul point positif des prévisions actuelles, tandis que les gouvernements fédéral et provinciaux s'engagent à mettre en œuvre un important plan de relance budgétaire et à envisager de gros déficits. Dans son budget de janvier, le gouvernement fédéral a annoncé l'octroi d'environ 12 milliards de dollars sur deux ans à de nouvelles dépenses d'infrastructure. Ces dépenses devraient être accompagnées de fonds équivalents investis au niveau provincial. C'est exactement ce que l'Ontario a annoncé dans son budget de mars 2009 : l'injection de sommes considérables dans l'infrastructure, combinée à une forte croissance des dépenses de programme. Comme le budget fédéral, celui de l'Ontario a un coût élevé : un déficit de 14,1 milliards de dollars l'an prochain.

LA SCÈNE PROVINCIALE

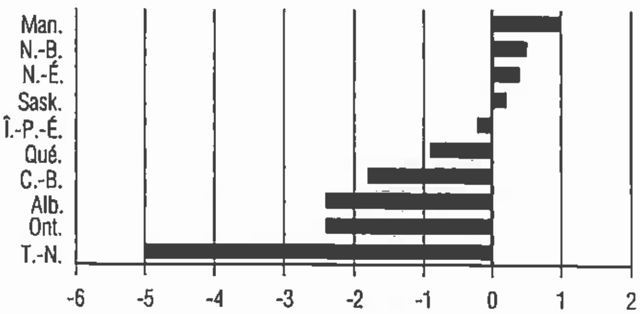
La récession mondiale, les faillites appréhendées dans les industries de l'automobile et des pâtes et papiers, et dans d'autres secteurs importants, de même que la faiblesse des prix des matières premières sont autant de facteurs qui paralysent les économies provinciales. Ce sont l'Ontario et l'Alberta qui souffriront le plus. D'autres provinces connaîtront certes des difficultés, mais de moindre ampleur. L'Ontario doit s'attendre à d'importantes contractions dans tous les secteurs, sauf le secteur public. De son côté, l'Alberta sera frappée par la léthargie de son secteur de l'énergie. La Colombie-Britannique aussi se prépare à enregistrer ses pires résultats depuis 1982; des replis marqués sont attendus dans les secteurs de la foresterie, de la fabrication et de la construction. À Terre-Neuve-et-Labrador, le PIB réel global dégringolera cette année, en raison essentiellement d'une diminution de la production de pétrole provoquée par une baisse de capacité dans les trois principaux champs pétrolifères extracôtiers de la province (Hibernia, Terra Nova et White Rose).

En Saskatchewan, le déclin de la demande mondiale d'engrais fertilisants nous a obligés à revoir à la baisse nos prévisions économiques. Cela dit, la province réussira quand même à afficher une croissance — quoique légère — du PIB réel cette année. Le Manitoba occupera la tête du peloton avec une croissance de 1 p. 100, tandis que deux des provinces maritimes — la Nouvelle-Écosse et le Nouveau-Brunswick — enregistreront une modeste croissance économique.

Cette faiblesse généralisée se dissipera au second semestre de 2009. Soutenues par les mesures fédérales de relance budgétaire et le redressement économique chez notre voisin du sud, toutes les provinces reprendront des forces en 2010.

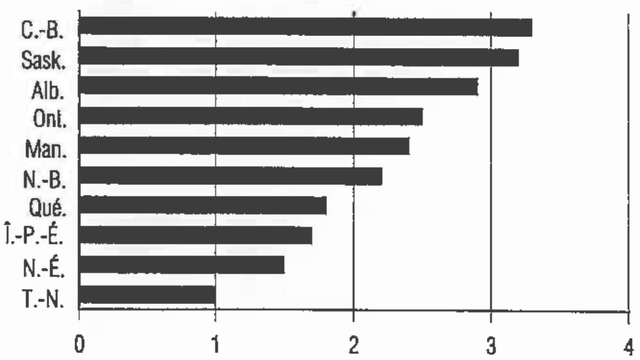
Le Québec est loin de souffrir autant que l'Ontario de la tourmente économique mondiale. Bien que les pertes d'emplois se multiplient sur les marchés du travail au Québec, l'économie intérieure ne connaîtra qu'un léger recul. Grâce au maintien du programme provincial d'infrastructure, l'investissement public continuera de soutenir la croissance économique dans la province au cours des deux prochaines années. Dans l'ensemble, le PIB réel aux prix de base se contractera de 0,9 p. 100 en 2009. (Voir les graphiques 1 et 2.) L'Ontario est à la merci de la demande des consommateurs américains, qui poursuit sa chute. On s'attend à ce que l'économie ontarienne recule de 2,4 p. 100 cette année. Dans le secteur manufacturier malmené de la province, on comprime déjà les effectifs à un rythme accéléré; une autre contraction importante de la production devrait être essuyée cette année. Au mieux, le secteur se stabilisera l'an prochain. Comme tenu de l'état lamentable dans lequel se trouve l'industrie de l'automobile, les exportations devraient chuter de 55 p. 100 en 2008–2009! Les perspectives de

Graphique 1
PIB réel par province en 2009
(variation en pourcentage; en dollars de 2002)



Sources : Le Conference Board du Canada; Statistique Canada.

Graphique 2
PIB réel par province en 2010
(variation en pourcentage; en dollars de 2002)



Sources : Le Conference Board du Canada; Statistique Canada.

faillite déstabilisent encore plus l'industrie. L'automobile, il est vrai, retient le plus l'attention des médias, mais d'autres secteurs de l'Ontario sont eux aussi durement touchés. On prévoit que les investissements réels des entreprises diminueront de 13,8 p. 100 cette année. D'importantes mesures de relance budgétaire aideront toutefois la province à se redresser au cours des deux prochaines années. L'augmentation des dépenses publiques de programme et d'investissement ajoutera 1,2 point de pourcentage à la croissance des résultats en 2009. Le ralentissement s'estompera pour faire place graduellement à une reprise. Les provinces du centre du Canada profiteront grandement des mesures fédérales pour redémarrer l'économie. Dans l'ensemble, le taux d'accroissement du PIB réel devrait atteindre 1,8 p. 100 au Québec et 2,5 p. 100 en Ontario en 2010. (Ces prévisions dépendent toutefois de la reprise de l'économie américaine.)

Les possibilités économiques offertes par l'Ouest canadien se faisant moins alléchantes, la vague migratoire d'est en ouest déferle maintenant en sens inverse. Les pertes d'emplois dans la région de l'Atlantique ont été relativement modestes par rapport à la moyenne nationale, les ventes au détail demeurent vigoureuses et le marché de l'habitation, contrairement à celui d'autres régions, n'a pas montré de signes de fatigue. Pour la première fois en plus de 25 ans, la migration interprovinciale nette enregistrera des valeurs positives dans la région de l'Atlantique cette année. Comparativement à d'autres provinces, les perspectives y sont plus encourageantes. Le Nouveau-Brunswick évitera la récession en intensifiant les dépenses publiques d'infrastructure et en réduisant le fardeau fiscal des ménages. Cependant, plusieurs secteurs industriels de la province continueront d'éprouver des difficultés, engendrées par la récession aux États-Unis. Les pêcheries, la foresterie et la fabrication seront durement touchées, mais cela n'empêchera pas l'économie néo-brunswickoise d'afficher, selon nos prévisions, un gain de 0,5 p. 100 en 2009. On prévoit que ce taux s'accélérera à 2,2 p. 100 en 2010, année où commencera une partie des travaux préliminaires de conception et de génie en vue de la construction d'une deuxième raffinerie de produits pétroliers. Pour sa part, la Nouvelle-Écosse profitera elle aussi de mesures fiscales destinées à favoriser l'activité économique. L'économie sera stimulée également par la mise en valeur du gisement de gaz naturel extracôtier Deep Panuke. Globalement, la croissance du PIB réel en Nouvelle-Écosse s'établira à 0,4 p. 100 cette année. Comme il n'y a pas d'autre projet de construction de grande envergure en vue, la province n'enregistrera qu'une expansion modérée de 1,5 p. 100 l'an prochain, et ce, malgré le redressement de l'économie mondiale. Ancien fleuron de l'économie, l'industrie du pétrole et du gaz de la province a atteint son maximum; la production de gaz naturel décroissante limitera la croissance économique jusqu'en 2011, année où le gisement Deep Panuke commencera à être exploité. À Terre-Neuve-et-Labrador, une importante contraction des secteurs de la foresterie, des mines et de la fabrication fera chuter le PIB réel de 5 p. 100 cette année. Néanmoins, les perspectives de la province demeurent favorables, surtout dans l'industrie de la construction, si bien qu'on entrevoit une légère remontée de 1 p. 100 l'an prochain. Malgré une modeste contraction de 0,2 p. 100 cette année, l'Île-du-Prince-Édouard tirera bien son épingle du jeu cette année. L'an prochain, on prévoit une croissance économique de 1,7 p. 100 dans la province alors que les préparatifs en vue du développement à grande échelle de la production d'énergie éolienne iront bon train.

Le Manitoba sera l'une des rares provinces à profiter d'une croissance économique positive, d'un budget provincial équilibré et d'un niveau d'activité industrielle décent. Mais la province n'est pas complètement à l'abri de la faiblesse de l'économie mondiale et fait face à un certain nombre de risques. Quoiqu'il en soit, son économie devrait croître de 1 p. 100 en 2009 et de 2,4 p. 100 en 2010. L'économie saskatchewanaise a facilement surclassé toutes les autres économies provinciales l'an dernier. La robustesse ne s'est pas limitée aux secteurs primaire et industriel — l'économie intérieure entière était florissante. Toutefois, depuis le début de l'année, les ventes au détail, tout comme d'autres secteurs de l'économie intérieure, accusent un ralentissement. La Saskatchewan connaîtra encore des succès, mais sa croissance économique sera amputée cette année par une diminution de 18 p. 100 de la production de potasse. Malgré de généreuses réductions de l'impôt sur le revenu des particuliers et un programme d'infrastructure non négligeable, le taux de croissance du PIB réel dégringolera à 0,2 p. 100 en 2009. La Saskatchewan recevra un bon coup de pouce lorsque la production de potasse reprendra, si bien qu'on s'attend à une croissance économique de 3,2 p. 100 l'an prochain.

L'Alberta se prépare à afficher cette année ses pires résultats économiques depuis 1986. Le secteur de l'énergie s'est effondré vers la fin de l'année dernière et ne commencera à se relever qu'en 2010, lorsque les cours du pétrole remonteront et que les coûts de construction baisseront. On estime que la moitié des dépenses d'investissement dans les sables bitumineux prévues au départ pour cette année — environ 20 milliards de dollars — ont été reportées. Heureusement, ces investissements n'ont pas été annulés de façon permanente, et le retour des cours du pétrole à un niveau plus rentable rend les perspectives à long terme du secteur de l'énergie très encourageantes. Cet hiver, les activités de forage ont été fort décevantes; ce secteur aussi continuera d'être un maillon très faible de l'économie de la province jusqu'à ce que les prix de l'énergie (en particulier du gaz naturel) remontent. Compte tenu du fait que le secteur de l'énergie est passé par un cycle d'expansion et de ralentissement en quelques mois seulement, il n'est pas étonnant que d'autres secteurs en aient souffert. Les taux d'inoccupation des bureaux et des locaux industriels et commerciaux sont en hausse, surtout dans les banlieues. Dans l'ensemble, on prévoit que l'économie albertaine reculera de 2,4 p. 100 cette année avant de retrouver un rythme de croissance plus normal de 2,9 p. 100 en 2010.

La Colombie-Britannique ne verra aucune amélioration avant le début de l'année prochaine, c'est-à-dire lorsque les Jeux Olympiques d'hiver de 2010 donneront aux industries du tourisme, du divertissement et de la vente au détail de la province un élan indispensable. Mais les Jeux ne constituent pas le seul facteur à l'origine de l'importante reprise qui s'annonce. Après avoir perdu 1,8 p. 100 en 2009, le taux de croissance du PIB réel global de la province devrait dépasser celui de toutes les autres provinces pour s'établir à 3,3 p. 100 en 2010. Après plusieurs années éprouvantes, les secteurs forestier et manufacturier toucheront le fond cette année, mais contribueront positivement à la croissance à court terme par la suite.

L'ÉCONOMIE AMÉRICAINE

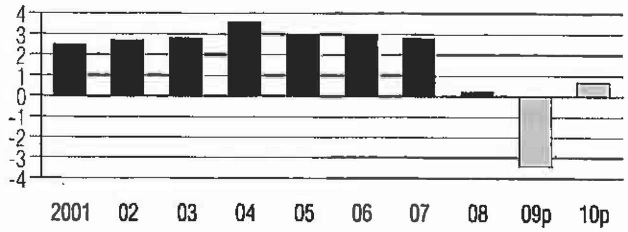
Officiellement, la récession sévit depuis plus d'un an[2] aux États-Unis. La correction sur les marchés immobiliers dure depuis encore plus longtemps. Les ventes de logements et la construction résidentielle ne cessent de baisser depuis le niveau record atteint au second semestre de 2005. Néanmoins, peu de signes pointent vers un renversement de cette tendance. Les dépenses massives de la Réserve fédérale et du Trésor américain finiront par renverser la vapeur et aideront l'économie américaine à se redresser vers la fin de l'année. Cependant, il faudra du temps pour que le plan de relance remette l'économie sur les rails. En attendant, la plupart des données ne sont guère encourageantes. Selon les prévisions actuelles, le PIB réel diminuera de 2,5 p. 100 en 2009, avant de remonter un peu, de 2,1 p. 100, en 2010.

Alors qu'il y a de faibles lueurs d'espoir que les marchés financiers et des actions ont atteint le fond du baril, le marché du travail est maintenant devenu l'épicentre de la secousse économique aux États-Unis. Un nombre effarant de 5 millions d'emplois ont disparu depuis le sommet atteint à la fin de 2007. Quelque 3,3 millions d'emplois se sont évaporés seulement entre novembre et mars dernier. À 8,5 p. 100, le taux de chômage est actuellement à son niveau le plus élevé depuis un quart de siècle. Malheureusement, les principaux indicateurs du marché du travail — notamment les demandes d'assurance-emploi, le nombre d'heures de travail et les annonces d'emplois temporaires — laissent présager d'autres pertes d'emplois à court terme.

La dégringolade des marchés du travail, combinée aux difficultés d'obtenir du crédit, a incité les consommateurs à acheter beaucoup moins de maisons et d'automobiles. En fait, la dernière fois que les ventes d'automobiles américaines ont été aussi faibles, c'était au début des années 1980, lorsque l'économie était aux prises avec une grave récession. Les ventes d'automobiles n'afficheront probablement pas d'amélioration sensible tant que l'avenir de General Motors et de Chrysler ne sera pas scellé et que le crédit pour l'achat d'automobiles ne sera pas plus accessible. Les ventes de logements nouveaux et existants ont aussi sombré à un niveau équivalant à presque la moitié des pics atteints pendant la bulle immobilière en 2005-2006. Les ventes seraient encore plus maigres si ce n'était de l'augmentation des ventes après saisie immobilière, qui représentent environ les deux tiers des ventes en Californie et en Floride. Dans l'ensemble, les dépenses des ménages américains devraient baisser de 3,4 p. 100 en 2009 — une baisse phénoménale en comparaison de ce qu'on a pu observer pendant les récessions qui ont secoué l'économie américaine depuis la Seconde Guerre mondiale. (Voir le graphique 3.)

On espère que les mesures stratégiques mises en œuvre pendant les derniers mois stabiliseront l'économie et restaureront la confiance. En fait, la politique budgétaire américaine est sans précédent. Le Congrès a voté près de 800 milliards de dollars de réduction d'impôts et de hausses des dépenses, pendant que l'administration Obama intervient pour aider les propriétaires immobiliers menacés par des saisies. La Réserve fédérale a imprimé de la monnaie pour

Graphique 3
Baisse phénoménale des dépenses
(dépenses de consommation réelles américaines, variation en pourcentage)



p = prévisions
Sources : Le Conference Board du Canada; Bureau of Economic Analysis (BEA) des États-Unis.

acheter des valeurs mobilières, prêtant de l'argent aux investisseurs pour acheter des titres en difficulté et donnant des garanties de prêts et d'actifs aux institutions financières malmenées. Ces initiatives devraient donner des résultats. De plus, l'aide aux États et aux administrations locales, et l'accroissement des prestations aux chômeurs, autres mesures comprises dans le plan de relance, soulageront les marchés du travail ce printemps et cet été. Enfin, le plan de l'administration Obama devrait faire exploser les activités de refinancement dans le secteur immobilier pendant les prochains mois.

LA POLITIQUE MONÉTAIRE

Au premier trimestre de 2009, les banques centrales et les gouvernements nationaux du monde entier ont poursuivi leurs efforts pour apporter une solution ordonnée à la crise des marchés financiers et atténuer les effets des remous financiers sur l'économie globale. Ces actions semblent avoir stabilisé la situation et arrêté l'hémorragie. Toutefois, les tentatives pour réanimer l'économie par la détente monétaire ont, jusqu'ici, été entravées par l'attitude défensive des participants au marché et n'ont connu que des réussites limitées.

Les grandes banques centrales ont abaissé leurs taux d'intérêt de façon notable depuis septembre 2008. En décembre, la Réserve fédérale américaine (la Fed) est intervenue une dernière fois sur les taux d'intérêt en situant la fourchette cible du taux des fonds fédéraux entre zéro et 0,25 p. 100. Cette intervention était essentiellement inévitable, puisque la Fed avait de la difficulté, dans le cadre de ses opérations quotidiennes sur le marché libre, à maintenir le taux effectif des fonds fédéraux au-dessus de 0,25 p. 100. La Banque centrale européenne et la Banque d'Angleterre, à l'origine du mouvement à la baisse des taux d'intérêt en 2008, ont depuis septembre réduit leurs taux d'intérêt de 275 et 450 points de base, respectivement; ces derniers se sont maintenant stabilisés à des niveaux qui n'avaient jamais été aussi bas. Chez nous, la Banque du Canada a considérablement amputé les taux d'intérêt depuis septembre, portant le taux du financement à un jour à 0,25 p. 100.

Dans un environnement où les taux d'intérêt sont si bas, la question se pose à présent de savoir comment les banques centrales pourraient donner un coup de fouet supplémentaire à l'économie. Alors que cette question est des plus pressantes aux États-Unis (où les taux d'intérêt sont au plus bas et ne sauraient être encore abaissés), les principales banques centrales du monde soupèsent les diverses solutions. En ce moment, la plupart d'entre elles ont signalé qu'elles opteraient ou étaient prêtes à opter pour l'assouplissement quantitatif ou le desserrement du crédit — processus qui leur permet d'émettre de l'argent en achetant des titres aux banques. (Voir l'encadré « Qu'entend-on par assouplissement quantitatif ? ») La Réserve fédérale américaine et la Banque d'Angleterre ont déjà présenté leur plan définitif à cet effet.

Qu'entend-on par assouplissement quantitatif?

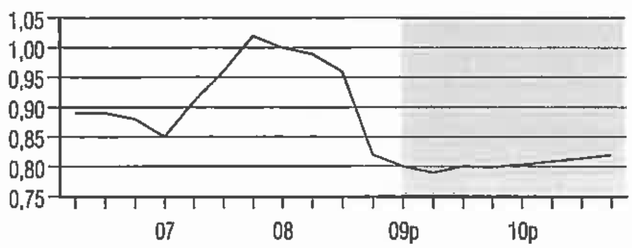
Dans un contexte marqué par des taux d'intérêt à leur niveau le plus bas ou presque, les banques centrales sont nombreuses à se tourner vers l'assouplissement quantitatif pour remettre leurs économies sur pied. Cela consiste essentiellement à faire fonctionner la « planche à billets ». L'argent est ensuite utilisé pour acheter des actifs sur le marché — surtout des obligations d'État, mais aussi des titres adossés à des actifs et des obligations de sociétés. Le but est d'injecter une grande quantité d'argent dans le système bancaire. Les banques centrales sont également plus enclines à acheter des obligations à long terme, ce qui en fait grimper le cours et en diminue le rendement. Il en résulte une baisse des taux d'intérêt appliqués aux hypothèques et à d'autres prêts à long terme.

Ces deux dernières années, les banques centrales ont fait des efforts sans précédent pour fournir des liquidités au système financier et elles ont baissé précipitamment les taux d'intérêt. Avec les mesures de stimulation monétaire que sont l'assouplissement quantitatif et le desserrement du crédit, elles feront face à d'importantes pressions inflationnistes provoquées par la politique monétaire à mesure que l'économie mondiale commencera à émerger de la récession. Elles ne devront donc pas oublier qu'elles pourraient rapidement devoir réaugmenter les taux d'intérêt et inverser le processus d'assouplissement quantitatif et de desserrement du crédit, afin d'empêcher l'inflation de s'installer.

À l'avenir, la Banque du Canada n'aura guère la possibilité de réduire encore plus le taux d'escompte. Elle renoncera donc probablement à toute réduction supplémentaire des taux d'intérêt en faveur de l'assouplissement quantitatif et du desserrement du crédit, ce qui pourrait libérer une partie des liquidités qu'elle a déjà injectées dans le système. D'ici à la fin de 2009, on s'attend à ce qu'elle commence à supprimer quelques-unes de ses mesures de stimulation pour chercher à anticiper sur la courbe de l'inflation. Malgré cette action préventive, il est vraisemblable qu'à partir de 2011, la Banque devra brièvement relever le taux d'escompte au-dessus du niveau neutre de 5 p. 100, afin de ne pas laisser l'inflation atteindre un taux indésirable.

Après avoir piqué du nez durant la dernière partie de 2008, le dollar canadien devrait normalement se stabiliser en 2009. (Voir le graphique 4.) On en a vu les premiers signes dans sa relative stabilité au cours du premier trimestre, et ceci malgré le rétrécissement de l'écart entre les taux d'intérêt canadien et américain, les attentes de plus en plus vives que la Banque du Canada prenne encore d'autres mesures de stimulation monétaire de l'économie sous la forme d'un assouplissement quantitatif ou d'un desserrement du crédit, et la modeste progression des cours du pétrole. Tout bien considéré, on prévoit que le dollar canadien restera proche de son cours actuel pour une grande partie de l'année. Par conséquent, il connaîtra sa première baisse annuelle depuis 2002. Cette baisse devrait normalement être de courte durée, puisque l'on s'attend à ce qu'il remonte modérément mais régulièrement durant le reste de la période de prévision.

Graphique 4
Moins de volatilité pour le dollar canadien
(taux de change É.-U./Canada)



p = prévisions
Sources : Le Conference Board du Canada; Statistique Canada.

POLITIQUE BUDGÉTAIRE

Une contraction de l'économie mondiale étant à l'ordre du jour cette année, tous les États du monde ont ouvert la vanne des stimulants économiques pour tenter d'inverser le courant. La situation n'est pas différente au Canada. En effet, le gouvernement fédéral a mis en œuvre un coûteux plan de relance pour faire redémarrer l'économie et renaître la confiance. Tout compris, le plan représente, en gros, 1,5 p. 100 du PIB réel de l'exercice en cours (qui a commencé le 1er avril) et 1,1 p. 100 de celui de 2010-2011. Il fera grimper les dépenses de programmes directes vertigineusement, de 13,1 p. 100, durant l'exercice 2009-2010 — le taux d'accroissement le plus rapide jamais enregistré. (Pour trouver des données comparables, il faut remonter à 1983.) Le plan comprend aussi des réductions d'impôts — de 10,5 milliards de dollars ces deux prochaines années au niveau fédéral. En même temps, on prévoit que le PIB nominal — la plus large mesure de l'assiette fiscale fédérale — se contracte de 4,1 p. 100 en 2009. Ensemble, la baisse du PIB nominal et la réduction des impôts se traduiront par une chute de 4,8 p. 100 des recettes fédérales totales durant l'exercice 2009-2010. Par conséquent, le gouvernement fédéral s'attend à un déficit cumulatif de 76,5 milliards de dollars pour les trois prochains exercices et on ne pense pas qu'il puisse équilibrer ses comptes avant 2013. Cet enchaînement de déficits effacera 10 ans de remboursements de la dette fédérale et fera remonter celle-ci à 542,4 milliards de dollars, ce qui ajoutera 9,7 milliards par an au service de la dette sur trois ans.

Les gouvernements provinciaux comptent sur ces mêmes assiettes fiscales de l'impôt sur le revenu des particuliers et de celui des sociétés, et ils font également face à d'importantes réductions de recettes. En outre, l'effet direct de la baisse des cours des produits de base sur les recettes en redevances compliquera encore le problème. La montée régulière de ces cours avaient fait grimper les recettes à 21,6 milliards de dollars en 2008, plus de deux fois le montant de 2002. En 2009, toutefois, l'effondrement des cours des produits de base devrait encore soustraire 9,2 milliards aux recettes en redevances tandis que les recettes provenant des impôts sur le revenu des sociétés baisseront de 5,2 milliards de plus. Les gouvernements provinciaux auront bien du mal à absorber cette dégringolade des recettes, puisqu'ils devront à présent se procurer 8,9 milliards de dollars de financement de contrepartie pour l'infrastructure durant les deux prochains exercices. Avec les conséquences de la récession mondiale, ils se retrouveront, dans l'ensemble, avec un déficit de 34 milliards de dollars en 2009 (selon les comptes nationaux), après avoir connu un excédent de 400 millions en 2008. Bien que le déficit collectif annoncé dans les prévisions sur le redressement économique à moyen terme se réduise finalement de moitié d'ici à 2012, ce ne sera pas suffisant, en soi, pour que les budgets provinciaux se rééquilibrent. Par conséquent, les provinces feront tout pour juguler leurs dépenses et elles seront peut-être forcées d'augmenter les impôts une fois que l'économie se sera redressée en 2010.

Newfoundland and Labrador

- Oil extraction will plummet at offshore sites in 2009.
- Labour markets will deteriorate this year and next after a strong 2008.

Real GDP

	Growth	Ranking
2009	–5.0	#10
2010	1.0	#10

Credit Quality

A

Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–1.0	#2
2010	3.6	#8

Government & Background Information

Premier	Danny Williams
Next election	2012
Population (2009:1)	508,918
Government balance (2009–10)	–$750 billion

Sources: The Conference Board of Canada; Newfoundland and Labrador Finance.

Warning: Sharp Contraction Ahead

by Kris Shaw

Newfoundland and Labrador's economy will falter significantly in 2009, mainly due to weakness in the oil and gas sector. The main offshore sites—Hibernia, Terra Nova, and White Rose—have all matured, and production will decline naturally at these fields. Moreover, weak oil prices will act as an incentive to limit production in the near term. As a result, real mineral fuels output is expected to fall 22.1 per cent in 2009, dropping to a level not seen since 2001. Because this sector accounts for nearly one-fifth of provincial output, the steep decline will have a considerable impact on provincial gross domestic product. Other sectors that will suffer large setbacks in 2009 include metal mining and manufacturing, thanks in large part to weak global demand for commodities and newsprint. But unlike mineral fuels, these industries are expected to bounce back once the recovery sets in. Overall, the provincial economy is forecast to contract by 5 per cent in 2009 before rebounding with modest growth of 1 per cent in 2010.

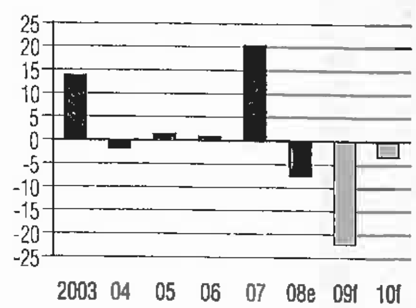
Despite the gloomy economic forecast, nominal investment spending is expected to expand by 11.2 per cent in 2009, thanks to significant non-residential construction. One of the most notable projects is the hydrometallurgical facility at Long Harbour. Expansions at offshore sites will also be a source of strength in the short and medium term. On the other hand, after climbing to a 20-year high in 2008, housing starts are expected to retreat significantly over the next two years. Weak global demand and limited access to credit are also causing several companies to review their investment schedules, and this poses a downward risk to the investment outlook.

Job prospects will deteriorate this year as the recession begins to take its toll on the labour market. Total employment in Newfoundland and Labrador will fall by a projected 1.5 per cent (about 3,300 jobs) and the unemployment rate will jump to 14.9 per cent. Positive net job creation is not expected to resume until 2011.

NO GOOD NEWS FOR GOODS PRODUCERS

Real output in the mineral fuels sector is expected to decrease by a whopping 22.1 per cent in 2009. The steep drop is largely due to the maturation of the three main offshore sites. Significant natural declines are anticipated at Hibernia, Terra Nova, and White Rose. Moreover, soft oil prices will encourage operators to limit production in the near term. As a result, total offshore oil production is expected

Oil Production Falls Off
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Economic Indicators
(2002 $; percentage change)

	2008	2009f	2010f
Real GDP (basic prices)	–0.1	–5.0	1.0
Consumer Price Index	2.9	0.5	2.7
Personal disposable income	–1.5	1.9	3.1
Employment	1.4	–1.5	0.0
Unemployment rate (level)	13.3	14.9	15.7
Retail sales	7.7	–0.1	3.6
Average weekly wages	3.5	0.2	2.6
Population	0.1	0.2	0.1

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

to fall below 100 million barrels this year for the first time since 2001 when only Hibernia was active. Mineral fuels will account for just 19.3 per cent of provincial output in 2009, also the lowest level since 2001.

Total offshore oil production is expected to fall below 100 million barrels for the first time since 2001 when only Hibernia was active.

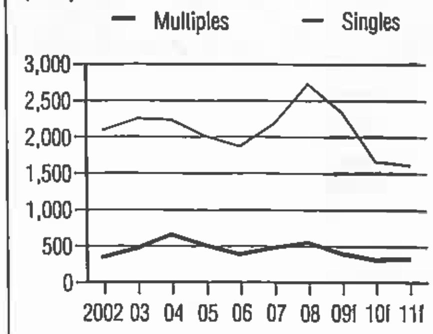
On a brighter note, the White Rose location has several satellite fields—including North Amethyst, the White Rose South Extension, and West White Rose—that could generate a future boost to production. These three fields contain a combined 214 million barrels of recoverable oil. The initial expansion will occur at the North Amethyst field, and Husky Energy says oil should begin flowing in late 2009 or early 2010. But even if these wells go forward as hoped, they will be insufficient to stave off a fall in total oil production. Thus, mineral fuels output will continue to decrease over the medium term as reserves at the three main oil fields become further depleted. In fact, the Conference Board expects that real output in this sector will fall another 14.4 per cent between 2009 and 2013.

Similar (if less dramatic) stories are occurring in other goods-producing sectors. For example, manufacturing output is forecast to decline 13 per cent in 2009. The struggling pulp and paper industry will bear a large portion of these losses. Indeed, the mill in Grand Falls-Windsor has already been closed, eliminating more than 200,000 tonnes of annual newsprint production. And although the Corner Brook operation will survive, one of its three machines will be shut down for eight weeks this year. Metal mining companies will also reduce output significantly in 2009 (–10.7 per cent) as they adjust to weak global demand by slashing production targets, announcing temporary shutdowns, scheduling extra maintenance, and laying off workers. Fortunately for metal miners and for manufacturers, their industries are projected to grow at very healthy rates once the recovery sets in.

HIGH EXPECTATIONS FOR INVESTMENT

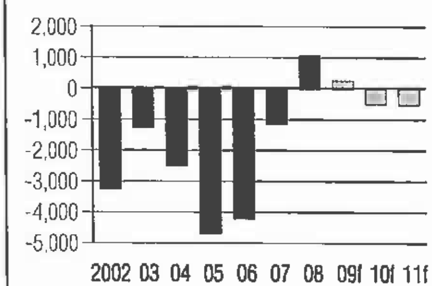
Despite the gloomy economic outlook, total investment spending is expected to expand by 11.2 per cent in 2009. This growth is due to significant non-residential construction. One of the most notable projects is the $2.2-billion hydrometallurgical facility

Housings Starts Retreat
(units)



f = forecast
Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

Interprovincial Migration: A Brief Reversal
(number of people)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Out of Equalization and Into Deficit

Although Newfoundland and Labrador is poised for a sharp contraction, there is some comfort in the province's greatly improved fiscal situation. The provincial government posted its fourth consecutive surplus in 2008–09, a record-smashing $2.4 billion. Soaring oil prices have allowed the government to reduce the net public debt per capita from $23,000 four years ago to $15,500 today. While this is still well above the national average, these debt-reduction efforts have put the province in a much better position for the lean times ahead.

The recession will have a substantial impact on the government's books. The government estimates that its revenues will decrease 24.5 per cent in fiscal 2009–10, mostly due to slumping offshore production and lower oil prices. As well, offshore royalties are expected to be down 41 per cent from the previous fiscal year. These estimates are based on an assumed average crude price of US$50 per barrel, closely in line with the Conference Board's own projection. Another recession-related development is a $383-million charge stemming from falling equity values in pension funds. Despite these setbacks, the government has raised the income threshold for the Low Income Tax Reduction (which exempts low-income earners from paying income tax) and the small business tax rate.

Program spending, on the other hand, will jump 15.6 per cent. Infrastructure spending will increase more than 50 per cent to $800 million, with most of the stimulus directed toward roads, educational facilities, and health-care infrastructure. Another large boost will go to health and community services. Expenditures in this area will increase 9.6 per cent in 2009–10.

The combination of falling revenues and increased expenditures will turn a hefty budget surplus into a deficit. The bitter irony is that the province recently obtained "have" status and has consequently lost its equalization payments. Fortunately, prudent use of royalty windfalls has cut the government's debt-servicing costs dramatically. As a result, stimulus measures can be undertaken during this recession without forfeiting too much in the way of recent gains. The province has planned for a $750-million shortfall this fiscal year, but anticipates a return to black ink no later than 2011–12.

at Long Harbour. Site preparation began earlier this spring, and construction is scheduled to end in 2013. Non-residential investment in the energy sector will also be strong over the forecast period thanks to offshore expansions and, later, the development of the Lower Churchill River's hydroelectric capacity. Indeed, nominal investment expenditures are forecast to rise another 44.2 per cent between 2010 and 2013.

Weak global demand and limited access to credit are causing several companies, especially those in resource sectors, to review their investment schedules.

Despite this generally strong investment outlook, there is some downside risk related to the ongoing economic and financial crisis. Weak global demand and limited access to credit are causing several companies, especially those in resource sectors, to review their investment schedules. Harvest Energy, for example, is deferring a $2-billion expansion of its aging oil refinery in Come by Chance until financial markets stabilize. It will instead begin working on various "de-bottlenecking" projects in 2009 at a cost of about $300 million. Similarly, the Iron Ore Company of Canada is reviewing plans for an $800-million expansion at its Labrador City operation, the first phase of which was scheduled to begin this year. If other projects like these ultimately fail to go forward, investment spending will advance less rapidly than expected in the years to come.

Investment prospects are bleaker in the residential sector. After a very robust 2008, spending is expected to fall significantly over the next two years. Housing starts will fall from 3,261 in 2008—the highest level in 20 years—to 2,700 units in 2009. Housing starts are then expected to drop below 2,000 units for the rest of the forecast period, leaving the province more dependent on megaprojects for investment growth.

LABOUR MARKETS WEAKEN IN 2009

Despite signs of future economic weakness, employment in Newfoundland and Labrador increased by 1.4 per cent last year. Large gains in construction and public administration were more than enough to offset losses in the manufacturing and other primary sectors. Higher demand for labour also raised the average weekly wage at a pace faster than the national average. But job prospects will deteriorate significantly in 2009 as the recession hits the labour market. Total employment will fall by an expected 3,300 jobs (a 1.5 per cent decrease) causing the unemployment rate to jump from 13.3 per cent to 14.9 per cent. The closure of the Grand Falls-Windsor newsprint mill will account directly for almost 800 of these jobs losses. Fortunately, positive net job creation will resume strongly in 2011. By 2013 the unemployment rate is forecast to drop to 10.3 per cent. As employment increases, total income from labour will also increase, rising by an average nominal rate of 5.9 per cent annually from 2010 to 2013.

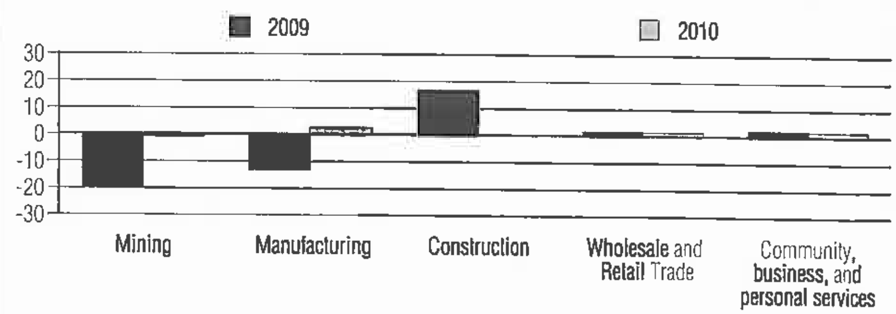
The strong labour markets of recent years have helped stem interprovincial outmigration. In 2008, the number of arrivals exceeded the number of departures by over 1,000. It was the first time since 1975 that the province gained more interprovincial migrants than it lost. Our forecast indicates that the province will welcome close to 300 more net migrants in 2009 despite weaker job prospects. These gains, while not huge, represent a considerable improvement over the large outflow experienced in the first seven years of the decade. Of course, the reversal says as much (and perhaps more) about labour markets in other parts of the country—particularly Alberta—which have become increasingly less attractive. Still, the tide of outmigration seems to be slackening. Over the forecast period, the average outflow of people from the province will be negative but relatively small at just 110 people lost per year.

Forecast Risks

- Many companies are reviewing planned investment spending. If conditions remain poor, these projects may be delayed or cancelled.
- If oil prices don't rebound, the incentive to begin production at satellite fields will be lower in the future.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Newfoundland and Labrador
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	30,528	32,357	32,780	30,218	27,616	27,477	27,924	28,682	28,840	28,792	29,006	29,392	31,471	27,925	29,007
	0.4	*6.0*	*1.3*	*–7.8*	*–8.6*	*–0.5*	*1.6*	*2.7*	*0.5*	*–0.2*	*0.7*	*1.3*	*6.6*	*–11.3*	*3.9*
GDP at basic prices (current $)	28,920	30,735	31,161	28,643	26,055	25,922	26,354	27,093	27,224	27,151	27,336	27,690	29,865	26,356	27,350
	0.8	*6.3*	*1.4*	*–8.1*	*–9.0*	*–0.5*	*1.7*	*2.8*	*0.5*	*–0.3*	*0.7*	*1.3*	*7.2*	*–11.7*	*3.8*
GDP at basic prices (constant $ 2002)	17,953	17,971	17,950	17,806	17,080	16,985	16,994	17,017	17,044	17,129	17,249	17,365	17,920	17,019	17,197
	0.1	*0.1*	*–0.1*	*–0.8*	*–4.1*	*–0.6*	*0.1*	*0.1*	*0.2*	*0.5*	*0.7*	*0.7*	*–0.5*	*–5.0*	*1.0*
Consumer Price Index (2002 = 1.0)	1.124	1.145	1.161	1.142	1.133	1.145	1.155	1.164	1.170	1.177	1.184	1.191	1.143	1.149	1.180
	0.8	*1.9*	*1.4*	*–1.7*	*–0.8*	*1.1*	*0.8*	*0.8*	*0.6*	*0.6*	*0.5*	*0.6*	*2.9*	*0.5*	*2.7*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.611	1.710	1.736	1.609	1.526	1.526	1.551	1.592	1.597	1.585	1.585	1.595	1.666	1.549	1.590
	0.7	*6.2*	*1.5*	*–7.3*	*–5.2*	*0.0*	*1.6*	*2.7*	*0.3*	*–0.8*	*0.0*	*0.6*	*7.8*	*–7.1*	*2.7*
Average weekly wages (**$**, industrial composite)	708.9	716.1	721.5	726.3	719.9	715.6	718.8	723.5	730.0	735.4	741.0	746.6	718.2	719.5	738.3
	0.9	*1.0*	*0.7*	*0.7*	*–0.9*	*–0.6*	*0.4*	*0.7*	*0.9*	*0.7*	*0.8*	*0.8*	*3.5*	*0.2*	*2.6*
Personal income (current $)	15,503	15,744	15,850	16,072	15,884	15,958	16,095	16,252	16,349	16,461	16,626	16,787	15,792	16,047	16,556
	–3.5	*1.6*	*0.7*	*1.4*	*–1.2*	*0.5*	*0.9*	*1.0*	*0.6*	*0.7*	*1.0*	*1.0*	*0.5*	*1.6*	*3.2*
Personal disposable income (current $)	12,393	12,722	12,825	13,010	12,836	12,907	13,020	13,148	13,208	13,310	13,440	13,560	12,738	12,978	13,380
	–4.4	*2.7*	*0.8*	*1.4*	*–1.3*	*0.6*	*0.9*	*1.0*	*0.5*	*0.8*	*1.0*	*0.9*	*0.7*	*1.9*	*3.1*
Personal savings rate	2.03	3.64	1.87	4.39	3.97	3.27	2.92	2.79	3.00	3.29	3.56	3.71	2.98	3.24	3.39
Population of labour force age (000s)	425	426	426	427	428	428	428	429	429	430	430	430	426	428	430
	0.3	*0.1*	*0.2*	*0.2*	*0.1*	*0.1*	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.4*	*0.5*	*0.3*
Labour force (000s)	255	255	252	253	253	254	256	256	256	257	257	258	254	255	257
	1.9	*0.2*	*–1.3*	*0.2*	*0.2*	*0.3*	*0.6*	*0.2*	*0.0*	*0.2*	*0.2*	*0.3*	*1.0*	*0.4*	*0.9*
Employment (000s)	222	222	218	218	216	217	217	217	217	216	217	218	220	217	217
	2.1	*–0.1*	*–1.9*	*0.0*	*–0.9*	*0.4*	*0.1*	*0.1*	*–0.4*	*–0.1*	*0.1*	*0.5*	*1.4*	*–1.5*	*0.0*
Unemployment rate	12.7	13.0	13.6	13.7	14.7	14.6	15.1	15.2	15.5	15.7	15.8	15.7	13	14.9	15.7
Retail sales (current $)	6,970	6,986	7,268	7,066	6,850	7,041	7,142	7,230	7,241	7,288	7,343	7,417	7072.3	7,066	7,322
	3.4	*0.2*	*4.0*	*–2.8*	*–3.1*	*2.8*	*1.4*	*1.2*	*0.2*	*0.6*	*0.8*	*1.0*	*8*	*–0.1*	*3.6*
Housing starts (units)	2,859	3,106	3,414	3,665	3,095	2,821	2,508	2,453	1,981	1,892	1,984	1,930	3261.0	2,719	1,947
	–9.7	*8.7*	*9.9*	*7.4*	*–15.6*	*–8.9*	*–11.1*	*–2.2*	*–19.2*	*–4.5*	*4.9*	*–2.7*	*23*	*–16.6*	*–28.4*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Prince Edward Island

- Largely shielded from U.S. trade shocks, Prince Edward Island's economy will fare better than the national average in 2009.
- A delay in key wind energy and infrastructure projects will postpone a major recovery in the Island's economy until late 2010.

Real GDP

	Growth	Ranking
2009	–0.2	#5
2010	1.7	#8

Credit Quality

A

Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–1.0	#4
2010	3.3	#9

Government & Background Information

Premier	Robert Ghiz
Next election	2011
Population (2009:1)	140,402
Government balance (projected 2008–09)	–$85.3 million

Sources: The Conference Board of Canada; P.E.I. Finance.

Recessionary Waves Hit P.E.I.'s Shores

by Sabrina Browarski

Prince Edward Island will feel the effects of the global financial crisis as 2009 unfolds. Since the beginning of the year, conditions in the Canadian economy have deteriorated significantly despite major stimulus initiatives tabled at the federal and provincial levels. While the national economy as a whole is vulnerable to waning consumer demand in the United States, the Prince Edward Island economy is relatively shielded from trade-related shocks. As a result, the Island's economy is forecast to contract by 0.2 per cent this year, a much smaller drop than the 1.7 per cent contraction in real gross domestic product at basic prices forecast for the broad Canadian economy. Real GDP will recover by 1.7 per cent next year as firms return to profitability.

The foundations of the Island economy will be eroded by several forces in 2009. Reduced corporate profits will propel the provincial economic downturn and will generate a negative ripple effect through the real domestic economy through the first half of the year. Labour markets on the Island will loosen considerably, with employment projected to fall by 1.5 per cent this year. The unemployment rate will rise to 11.9 per cent in 2009, when corporations will see profits fall by nearly 22 per cent. The jobless rate is expected to peak at 12.6 per cent in 2010. As a result of weaker job prospects, consumers will retrench. Growth in total consumer expenditures is expected to be only marginally positive in real terms. In an attempt to resuscitate their balance sheets, firms will cut back on business investment significantly, resulting in a 3.9 per cent cutback in total Island investment. Government spending on goods and services will remain an important source of growth for the province, with nominal spending averaging nearly 5 per cent over the next two years.

INDUSTRY SNAPSHOT

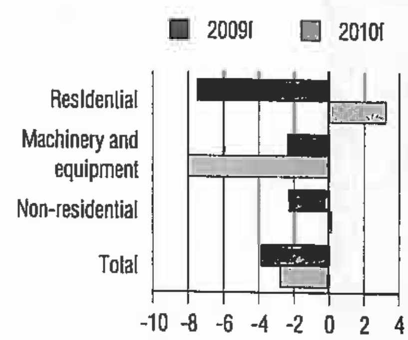
Trade data for 2008 indicate that although Prince Edward Island is somewhat sheltered from the gyrations in the American economy, the Island's economy will still be adversely affected in the coming year. The swift depreciation of the Canadian dollar—from above parity with the U.S. dollar in 2008 to as low as US$0.77 this past March—will generate little traction for the Island's goods and services south of the border, since U.S. markets continue to contend with significant job losses and capital and investment financing constraints. Other key export markets—the United Kingdom, the European Union, and Japan—will provide little help as they face non-existent growth in 2009 and only a feeble recovery in 2010.

Economic Indicators
(2002 $; percentage change)

	2008	2009f	2010f
Real GDP (basic prices)	1.0	–0.2	1.7
Consumer Price Index	3.4	–0.6	2.6
Personal disposable income	4.2	1.2	3.0
Employment	1.2	–1.5	0.2
Unemployment rate (level)	10.7	11.9	12.6
Retail sales	4.8	–1.0	3.3
Average **weekly** wages	2.4	1.8	2.1
Population	1.0	0.9	0.5

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Island Investment Nosedives in 2009
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

AGRICULTURE

Total agri-food exports edged up by 2.1 per cent to $520 million in 2008,[1] accounting for 61.3 per cent of P.E.I.'s total exports. Agri-food exports are typically dominated by sales of processed potatoes and seafood, of which nearly 85 per cent go to the United States. Steady demand by supermarkets and fast-food restaurants for name brands such as Cavendish and McCain will enable the agriculture sector to eke out growth of 2.9 per cent this year, despite the U.S. downturn. Demand for potato granules appears, similarly, to be recession-proof.

With only a negligible rebound in employment and personal disposable income forecast for 2010, growth in consumer spending will total 2.9 per cent.

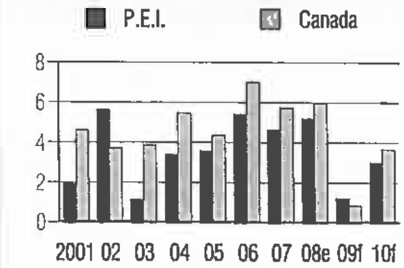
FISHING AND TRAPPING

The Island's fishing and trapping industry will suffer a 2 per cent contraction as struggling households choose to forgo relatively expensive lobster purchases. Efforts are now under way to have P.E.I. lobster certified as a "sustainable catch" by the London-based Marine Stewardship Council. Certification would open up the European Union markets to the Island's lobster products, which could bolster demand in the medium term. Mussels—which are less expensive than lobster—exhibit less price volatility, and will provide some offset to flagging lobster exports.

MANUFACTURING

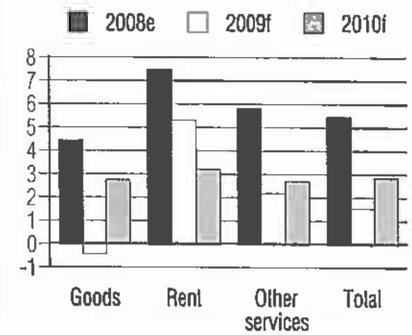
Most subcategories of machinery and equipment (M&E) and industrial goods will face weak demand south of the border in 2009, resulting in a forecast 4.2 per cent contraction in the Island's manufacturing sector. However, performance in higher value-added export products—such as jet turbines, power transmission, and specialized food-manufacturing equipment—will buck the general downward trend of M&E sales in the United States. Niche manufacturers serving the M&E needs of the food and beverage processing industry (such as Diversified Metal Engineering) will see continued sales growth in countries such as Brazil, China, South Africa, and Turkey where domestic food-processing capabilities are being expanded. Growth in manufacturing activity will, accordingly, rebound by 3.2 per cent in 2010.

Disposable Income Growth Slows
(percentage change)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Consumption Hit by Recession
(percentage change)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Budget Announces Large Deficit for 2009–10

Prince Edward Island's 2009 budget revealed that while the Island will fare better than most provinces in the coming year, it won't be immune to the ripple effects of the U.S. recession. Although total own-source revenues were up nearly $10 million relative to pre-budget estimates for fiscal year 2008-09, increased program spending and a spike in debt interest charges were enough to push the province into deficit territory. Granted, the increase in provincial revenues and an unexpected $3 million in help from federal sources did allow the P.E.I. Treasury to post a more modest $28.9-million deficit in fiscal year 2008–09 than the $41.3-million shortfall initially projected. A number of hospital-related spending initiatives were cancelled in the previous fiscal year, which enabled the province to rein in health-care spending.

Looking ahead, the provincial government will face more challenging prospects in the current fiscal year that began on April 1. Provincial Treasurer Wes Sheridan initially budgeted for a $34.9-million deficit this fiscal year, but the recent budget estimates indicate that the deficit will reach $85.3 million.

The sudden increase in the size of the expected deficit is the result of four key changes that have occurred since Budget 2008 was released. First, the agriculture sector will require greater assistance in the coming year. Larger payments will be made to potato farmers who lost their crops last year as a result of the wet summer. Second, P.E.I. will have to pay an unexpected $5.6 million to Nova Scotia for providing out-of-province health services to Island residents. The third factor that will cause the provincial deficit to creep higher will be upward adjustments made to public pensions to offset widespread stock market losses. Of the total deficit projected for 2009–10, $39.4 million of the loss is attributable to pension adjustments. Finally, total spending on the health-care sector will rise by $28 million in the coming year as a result of a number of modernization projects.

ISLANDERS CONTINUE TO SPEND

Recessionary headwinds from south of the border will trigger weak GDP performance in a number of key industries on the Island this year, and this will cause a sharp 21.8 per cent decline in corporate profits in 2009. However, since P.E.I. is less export-sensitive than other provinces, it will suffer a more moderate hit to corporate profits than we will see at national level where Canadian corporate profits are expected to contract by nearly 32 per cent this year!

The effects of lower corporate profits will naturally trickle into the Island's real economy, causing firms to scale back employment by 1.5 per cent in 2009, with only a modest 0.2 per cent rebound expected in 2010. Personal disposable income growth will slip to 1.2 per cent this year as a result of looser labour market conditions and the recent drop in household wealth from falling stock and home values.

Steady demand by supermarkets and fast-food restaurants for name brands such as Cavendish and McCain will enable the agriculture sector to eke out growth of 2.9 per cent this year, even amid the U.S. downturn.

Although Islanders will scale back spending growth this year to 1.5 per cent in response to softer labour markets, only three provinces will post higher growth in total consumer spending in 2009. Expenditures on rent and other services will remain robust, even as Islanders trim discretionary services from their budgets this year. With only a negligible rebound in employment and personal disposable income forecast for 2010, growth in consumer spending will total 2.9 per cent.

GOVERNMENT EXPENDITURES BOOSTED BY PUBLIC INVESTMENT

Fiscal stimulus can play a legitimate role in bolstering domestic demand in times of economic duress, and all levels of government in Canada have been called upon to stimulate local spending to counteract the global recession. The Prince Edward Island government demonstrated prudent foresight in recent months, introducing an unprecedented five-year, $510-million capital spending plan and a six-year, $27.5-million Island Community Fund. These projects will receive up to $60 million in assistance between 2010 and 2014 from the federal Gas Tax Fund. Of the total federal assistance package, $30 million will be directed to provincial water and sewer projects, $18 million to other municipal services, and the remaining $12 million to "soft-cost" (or non-construction) projects.

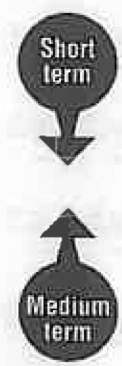
Thanks to these ambitious initiatives, public capital expenditures are forecast to grow by a healthy 16.1 per cent in 2009 following the largest single-year government infrastructure investment package (valued at $31.6 million) in fiscal year 2008–09. Government spending on goods and services will expand at a still hearty pace of 5.6 per cent in 2009, although the rate of growth will be well below the pace set in recent years.

INVESTMENT REBOUND DELAYED BY RECESSION

Although total investment spending in Prince Edward Island is forecast to contract by nearly 4 per cent this year and a further 3 per cent next year, the province's new $510 million capital spending plan, coupled with a landmark $1 billion provincial wind energy strategy, will enable a turnaround in investment intentions as early as 2011, and will fuel average annual growth in total investment of 10.5 per cent in 2011 and 2012.

1 Strategis Trade Data Online, Industry Canada (April 2009).

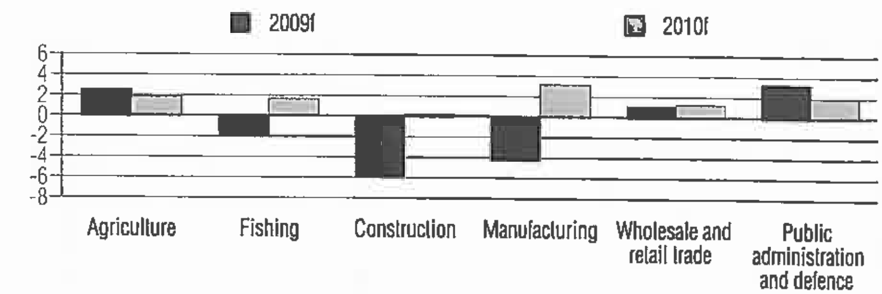
Forecast Risks



- A delayed recovery in U.S. demand for seafood products could hamper a recovery in the Island's fishing and trapping industry.
- Prince Edward Island could benefit from up to $60 million for infrastructure renewal under the Atlantic Gateway trade initiative.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Prince Edward Island
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	4,580	4,685	4,729	4,670	4,648	4,672	4,723	4,783	4,803	4,834	4,877	4,934	4,666	4,706	4,862
	−1.5	*2.3*	*0.9*	*−1.2*	*−0.5*	*0.5*	*1.1*	*1.3*	*0.4*	*0.6*	*0.9*	*1.2*	*2.5*	*0.9*	*3.3*
GDP at basic prices (current $)	4,176	4,277	4,321	4,273	4,255	4,280	4,328	4,383	4,396	4,421	4,457	4,505	4,262	4,312	4,445
	−1.0	*2.4*	*1.0*	*−1.1*	*−0.4*	*0.6*	*1.1*	*1.3*	*0.3*	*0.6*	*0.8*	*1.1*	*3.2*	*1.2*	*3.1*
GDP at basic prices (constant $ 2002)	3,784	3,806	3,815	3,827	3,795	3,791	3,799	3,811	3,829	3,851	3,876	3,904	3,808	3,799	3,865
	0.4	*0.6*	*0.2*	*0.3*	*−0.8*	*−0.1*	*0.2*	*0.3*	*0.5*	*0.6*	*0.6*	*0.7*	*1.4*	*−0.2*	*1.7*
Consumer Price Index (2002 = 1.0)	1.149	1.184	1.199	1.167	1.151	1.165	1.173	1.179	1.186	1.193	1.201	1.208	1.175	1.167	1.197
	0.4	*3.0*	*1.3*	*−2.6*	*−1.4*	*1.2*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*3.4*	*−0.6*	*2.6*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.104	1.124	1.133	1.117	1.121	1.129	1.139	1.150	1.148	1.148	1.150	1.154	1.119	1.135	1.150
	−1.5	*1.8*	*0.8*	*−1.4*	*0.4*	*0.7*	*0.9*	*0.9*	*−0.2*	*0.0*	*0.2*	*0.4*	*1.8*	*1.4*	*1.3*
Average weekly wages ($, industrial composite)	546.5	559.0	562.0	575.4	572.7	568.1	569.8	572.9	577.7	580.8	584.4	588.0	560.7	570.9	582.7
	−0.4	*2.3*	*0.5*	*2.4*	*−0.5*	*−0.8*	*0.3*	*0.5*	*0.9*	*0.5*	*0.6*	*0.6*	*2.4*	*1.8*	*2.1*
Personal income (current $)	4,047	4,056	4,079	4,130	4,074	4,109	4,144	4,173	4,197	4,225	4,270	4,308	4,078	4,125	4,250
	1.9	*0.2*	*0.6*	*1.3*	*−1.3*	*0.9*	*0.8*	*0.7*	*0.6*	*0.7*	*1.1*	*0.9*	*4.1*	*1.2*	*3.0*
Personal disposable income (current $)	3,237	3,258	3,282	3,322	3,271	3,302	3,331	3,355	3,370	3,396	3,432	3,459	3,275	3,315	3,414
	2.5	*0.6*	*0.7*	*1.2*	*−1.5*	*0.9*	*0.9*	*0.7*	*0.4*	*0.8*	*1.1*	*0.8*	*5.2*	*1.2*	*3.0*
Personal savings rate	−6.44	−7.31	−8.00	−5.89	−6.50	−7.26	−7.64	−7.78	−7.55	−7.21	−6.91	−6.74	−6.91	−7.29	−7.10
Population of labour force age (000s)	114	114	115	115	115	116	116	116	116	116	117	117	115	116	117
	0.1	*0.3*	*0.6*	*0.4*	*0.0*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	*0.3*	*1.1*	*1.0*	*0.8*
Labour force (000s)	79	79	79	78	78	79	79	79	79	79	79	80	79	79	79
	1.6	*0.2*	*−0.3*	*−0.4*	*−0.8*	*1.2*	*0.3*	*−0.2*	*0.0*	*0.4*	*0.4*	*0.4*	*1.7*	*−0.1*	*0.9*
Employment (000s)	71	71	70	69	69	69	69	69	69	69	69	70	70	69	69
	1.5	*0.0*	*−0.8*	*−1.0*	*−1.3*	*1.2*	*0.2*	*−0.3*	*−0.4*	*0.1*	*0.3*	*0.5*	*1.2*	*−1.5*	*0.2*
Unemployment rate	10.3	10.4	10.8	11.4	11.9	11.9	12.0	12.0	12.4	12.7	12.7	12.6	10.7	11.9	12.6
Retail sales (current $)	1,695	1,710	1,732	1,688	1,634	1,687	1,711	1,726	1,727	1,738	1,751	1,766	1,706	1,690	1,746
	2.3	*0.9*	*1.3*	*−2.5*	*−3.2*	*3.2*	*1.4*	*0.9*	*0.1*	*0.6*	*0.8*	*0.8*	*4.8*	*−1.0*	*3.3*
Housing starts (units)	626	754	747	721	604	562	562	564	579	582	602	625	712	573	597
	−27.1	*20.5*	*−0.9*	*−3.5*	*−16.2*	*−6.9*	*−0.1*	*0.4*	*2.6*	*0.6*	*3.3*	*3.8*	*−5.1*	*−19.5*	*4.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Nova Scotia

- Massive infrastructure spending will help the economy avert recession.
- The resource industry will continue to struggle as natural gas production declines.

Real GDP

	Growth	Ranking
2009	0.4	#3
2010	1.5	#9

Credit Quality

A+

Standard & Poor's

Retail Sales

	Growth	Ranking
2009	0.6	#1
2010	3.1	#10

Government & Background Information

Premier	Rodney MacDonald
Next election	2009
Population (2009:1)	939,531
Government balance (2008–09)	$212.9 million

Source: The Conference Board of Canada; Nova Scotia Ministry of Finance.

Solid Investment Stimulates Economy

by Prince Owusu

An $800-million economic stimulus package announced by the provincial government early this year will help the province avert recession. The three-year infrastructure stimulus package, which is expected to filter into the economy by the second half of this year, will add more vigour to the construction industry already bustling with work on the $700-million Deep Panuke offshore natural gas project. As a result of strong public and private investment spending, real gross domestic product will advance by 0.4 per cent this year.

Apart from the construction industry (where economic activity remains healthy), the goods-producing industries are mired in recession. Declining natural gas production will drag down growth in the primary sector over the next two years. Fishermen struggling with rock-bottom prices for their catches are expected to reduce fish landings this year in an effort to shore up prices. Even though a lower Canadian dollar is expected to provide relief for exporters, the manufacturing sector will be pulled down by the sharp reduction in consumer demand south of the border.

The weakness in the provincial economy is not limited to the goods-producing sector. Growth in the service sector will slow as job losses constrain income growth. The unemployment rate is forecast to rise over the next two years. Personal services, as well as patronage at restaurants and amusement centres, will be affected this year. Weaker growth in wholesale trade is expected. Business services, including technical and call centre activities, will fall victim to the global economic recession and impede gains in the service sector. Given the weaker global outlook, the tourism and transportation industries are expected to face tough times in 2009. The outlook is expected to improve next year as the U.S. economy recovers. Real GDP is forecast to expand by 1.5 per cent in 2010 as the province's industrial production picks up steam and growth in the service sector intensifies.

PUBLIC CAPITAL PROJECTS BOOST CONSTRUCTION

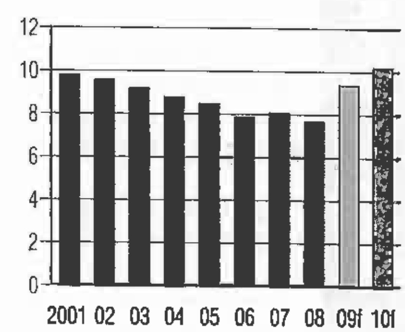
The construction industry is expected to fire on only one cylinder as residential construction investment fizzles out. Over the past decade, residential investment increased by an average of 10 per cent per year. A large correction is projected as the economy continues to bleed jobs, leaving consumers reluctant to make major purchases such as a home. Even with borrowing costs reduced to the barest minimum,

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	2.2	0.4	1.5
Consumer Price Index	3.0	0.0	2.6
Personal disposable income	4.7	1.6	2.6
Employment	1.2	–0.5	–0.7
Unemployment rate (level)	7.7	9.4	10.2
Retail sales	4.5	0.6	3.1
Average weekly wages	2.4	1.6	2.5
Population	0.2	0.2	0.2

Sources: The Conference Board of Canada; Statistics Canada.

Unemployment Rate Heading Higher
(per cent)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

housing starts are projected to decline at an annual average pace of 12.7 per cent this year and next.

On the positive side, private and public non-residential investment is expected to advance at a healthy clip. Work is progressing on Encana's Deep Panuke offshore natural gas platform. At least 30 per cent of the $700-million capital outlays on this project will occur in the province. Work is also expected to begin this year on the $350-million container terminal at the Strait of Canso, providing up to 500 construction jobs over the three-year construction period.

Over the past decade, residential investment increased by an average of 10 per cent per year, but a large correction is expected in the near term.

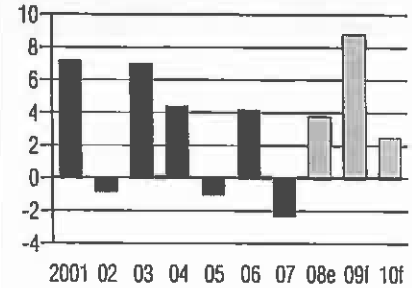
The provincial government is expected to spend an additional $800 million on infrastructure programs over three years to help insulate the economy from the global recessionary conditions. These projects will help boost growth in the construction industry by 8.8 per cent this year. Next year, the industry will manage to advance by 2.5 per cent, thanks to the fiscal stimulus package, the bulk of which is expected to be spent in 2010.

RESOURCE INDUSTRIES IN A DOWNTURN

The primary sector will face a steep contraction this year as the mining, fishing, and forestry industries all struggle. Natural gas production peaked last year at the Sable Island offshore natural gas field following the installation of a compression platform. Real mining output is projected to drop by 6.6 per cent over 2009–10. The industry is expected to languish until the Deep Panuke natural gas field comes online in 2011.

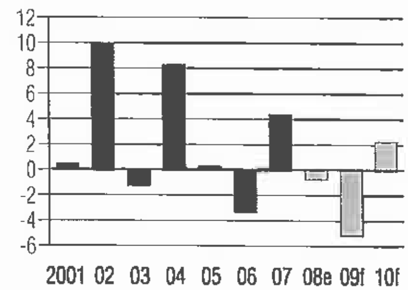
South of the border, the recession has dampened demand for lobster, leading to large inventories of unsold lobster from last year. Lobster prices have fallen dramatically to $3.50 per pound—far below the break-even point for lobster fishermen. With banks unwilling to finance canneries holding large inventories, it is very likely lobster landings will drop this year. The fishing industry will contract by 4 per cent, before recovering next year with growth of 2.2 per cent as market conditions improve.

Construction Holding Up
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Manufacturing in Recession
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Stimulus Plan to Boost Fiscal Debt

Nova Scotia is not alone in piling up debt to fend off the winds of recession blowing through the industrialized economies. Its Maritime neighbours, as well as Quebec and Ontario and even the federal government, are planning on substantial borrowing to make up for the revenue shortfall resulting from the weaker economy while providing the needed stimulus to jolt the economy back into health.

Last month, the provincial government announced a $1.9 billion economic stimulus package to bolster the economy over the next three years. Most of the money is for projects already slated to go ahead, but the package also includes $800 million in new infrastructure spending on roads, information technology, education, health, the justice system, and other capital initiatives. In undertaking these massive spending initiatives, the provincial government has opted to suspend its debt repayment plan—a move that will see the provincial debt increase by $1.4 billion between now and 2012 to reach $13.5 billion. Based on the Conference Board's population projection, each Nova Scotian's share of the provincial debt will increase by $1,361 to reach $14,259 by 2012.

The good news is that the government stimulus plan is expected to create or maintain 20,000 jobs and help the economy grow, thus allowing the debt-to-GDP ratio to return to its current level of 36.7 per cent in the near future. Another positive is that the government plans to balance the budget for this fiscal year thanks to the Canada–Nova Scotia Offshore Accord. This accord, reached in 2005 between the province and the federal government, allows the province to receive 100 per cent of offshore royalties without any of it being clawed back from the equalization transfer payments Nova Scotia receives from the federal government. The provincial government introduced legislation that would allow it to use the accord money to pay for the stimulus plan rather than to pay down the debt. However, on May 4 the opposition parties voted against the change—and thereby brought down the Progressive Conservative government of Premier Rodney MacDonald. Nova Scotians go to the polls on June 9 to elect a new government. Until then, the fate of the stimulus plan remains unclear.

Facing depressed prices, and with several print media houses unable to survive the ravages of the recession, a number of lumber and paper mills are implementing down time. Others have shut down completely. Real forestry output is expected to plummet 11.3 per cent this year, but the industry is expected to come back to life next year as demand conditions in the U.S. improve.

MANUFACTURERS' PAIN WILL CONTINUE THIS YEAR

Fish-processing activities will suffer from the downturn in fish landings. Other manufacturing sectors are hurting as well. The collapse in the North American car industry has hit the province's tire industry. With credit drying up for U.S. consumers, car sellers south of the border are facing tough times. And with fewer cars rolling off North American auto assembly lines and auto companies teetering on the brink of bankruptcy, tire-maker Michelin has announced production curtailments at its Nova Scotia plants and laid off some workers.

After declining to 7.7 per cent in 2008, the unemployment rate is expected to climb to 10.2 per cent by 2010

Demand for pulp and paper and lumber-related products is expected to remain weak this year. The only sectors currently experiencing export growth are aerospace, rubber, chemical, spring and wire products, and navigational instruments. The majority of the aerospace activity in the province is geared toward defence capabilities, a segment that is least affected by economic downturns. Several aerospace firms in the province—including C-Vision, Composite Atlantic, and L-3 Communications Canada—are busy filling orders. IMP has a $591-million contract to maintain Canada's CH-149 Cormorant search-and-rescue military helicopters for the next seven years. The company recently won a contract worth more than $50 million to replace the wings on six Royal Norwegian Air Force P-3s. The contract will result in the manufacture of several hardware and avionic components in the province.

While activity in the aerospace industry remains healthy, aerospace represents only a small share of the manufacturing sector. Overall, real manufacturing output is forecast to decline by 5.1 per cent this year, before rebounding by 2.3 per cent in 2010 along with the recovery south of the border.

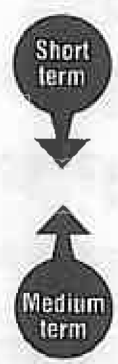
DOMESTIC DEMAND OUTLOOK

Even with the government stimulus plan, the province is expected to lose jobs this year and next as companies trim payrolls in response to lower demand and production. After dropping to 7.7 per cent in 2008, the unemployment rate is expected to climb to 10.2 per cent by 2010. With job losses and weaker wages gains, labour income will deteriorate. As a result, consumer spending is expected to wane this year, with retail sales advancing at a slower pace of 0.6 per cent.

Container traffic at the Port of Halifax is expected to decline in 2009 as global trade slows. Air Canada's regional carrier Jazz Air has reduced its capacity by 5 per cent, eliminating 187 flight attendant positions at its Halifax base. With the manufacturing sector struggling to keep truckers busy and with lower traffic at ports of entry, growth in the transportation and warehousing industry is expected to decline by 0.7 per cent in 2009 before managing a weak recovery of 0.7 per cent next year.

Even though the depreciation of the Canadian dollar against its U.S. counterpart gives American tourists visiting the province more spending power, the economic meltdown in the U.S. (and elsewhere in Canada, as well) will limit the number of visitors to the province, hurting businesses that cater to tourists. Nova Scotia is home to many technical and client services operations that cater to businesses around the globe; but with businesses struggling in the face of the global financial crisis, client and technical service centres in the province are not likely to launch any ambitious expansions. Growth in the commercial services industry is expected to contract by 0.2 per cent this year, before recovering by 1.1 per cent next year as the global economy begins to recover.

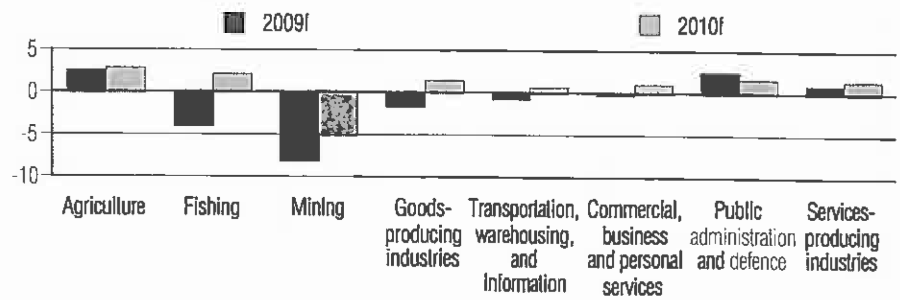
Forecast Risks



- Delays in getting the stimulus funds out quickly could spell bad news for the economy.
- Confirmation of recoverable onshore unconventional natural gas reserves could bring huge benefits to the province.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



f = forecast
Source: The Conference Board of Canada.

Key Economic Indicators: Nova Scotia
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	34,176	34,840	35,103	34,341	33,608	33,526	33,699	34,050	34,397	34,629	34,971	35,411	34,615	33,721	34,852
	2.1	*1.9*	*0.8*	*−2.2*	*−2.1*	*−0.2*	*0.5*	*1.0*	*1.0*	*0.7*	*1.0*	*1.3*	*4.6*	*−2.6*	*3.4*
GDP at basic prices (current $)	31,489	32,128	32,397	31,708	30,999	30,927	31,074	31,392	31,695	31,886	32,179	32,567	31,931	31,098	32,082
	2.8	*2.0*	*0.8*	*−2.1*	*−2.2*	*−0.2*	*0.5*	*1.0*	*1.0*	*0.6*	*0.9*	*1.2*	*5.4*	*−2.6*	*3.2*
GDP at basic prices (constant $ 2002)	26,734	26,821	26,934	26,842	26,899	26,885	26,928	27,018	27,120	27,240	27,388	27,559	26,833	26,932	27,327
	0.5	*0.3*	*0.4*	*−0.3*	*0.2*	*−0.1*	*0.2*	*0.3*	*0.4*	*0.4*	*0.5*	*0.6*	*1.4*	*0.4*	*1.5*
Consumer Price Index (2002 = 1.0)	1.140	1.168	1.177	1.149	1.141	1.154	1.164	1.174	1.178	1.185	1.192	1.200	1.159	1.158	1.189
	0.6	*2.5*	*0.8*	*−2.4*	*−0.8*	*1.2*	*0.8*	*0.9*	*0.3*	*0.6*	*0.6*	*0.6*	*3.0*	*0.0*	*2.6*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.178	1.198	1.203	1.181	1.152	1.150	1.154	1.162	1.169	1.171	1.175	1.182	1.190	1.155	1.174
	2.4	*1.7*	*0.4*	*−1.8*	*−2.4*	*−0.2*	*0.3*	*0.7*	*0.6*	*0.2*	*0.4*	*0.6*	*4.0*	*−3.0*	*1.7*
Average weekly wages (**$**, industrial composite)	642.2	652.0	652.9	654.5	659.0	658.6	660.8	664.7	670.8	675.1	679.5	683.9	650.4	660.8	677.3
	0.3	*1.5*	*0.1*	*0.3*	*0.7*	*−0.1*	*0.3*	*0.6*	*0.9*	*0.6*	*0.7*	*0.6*	*2.4*	*1.6*	*2.5*
Personal income (current $)	29,795	29,906	30,096	30,243	30,340	30,337	30,490	30,698	30,915	31,109	31,405	31,654	30,010	30,466	31,271
	1.6	*0.4*	*0.6*	*0.5*	*0.3*	*0.0*	*0.5*	*0.7*	*0.7*	*0.6*	*1.0*	*0.8*	*3.8*	*1.5*	*2.6*
Personal disposable income (current $)	23,576	23,795	23,978	24,092	24,131	24,151	24,277	24,446	24,578	24,760	24,987	25,169	23,860	24,251	24,873
	2.0	*0.9*	*0.8*	*0.5*	*0.2*	*0.1*	*0.5*	*0.7*	*0.5*	*0.7*	*0.9*	*0.7*	*4.8*	*1.6*	*2.6*
Personal savings rate	−3.26	−2.79	−3.90	−1.59	−2.84	−3.60	−3.97	−4.12	−3.89	−3.54	−3.28	−3.09	−2.89	−3.63	−3.45
Population of labour force age (000s)	767	768	769	770	771	772	773	774	776	778	779	780	769	773	778
	0.2	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.1*	*0.1*	*0.6*	*0.6*	*0.7*
Labour force (000s)	488	491	492	494	499	498	497	498	498	498	499	499	491	498	499
	−0.2	*0.7*	*0.2*	*0.4*	*1.0*	*−0.2*	*−0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.9*	*1.3*	*0.2*
Employment (000s)	450	452	455	455	455	451	449	448	447	447	448	449	453	451	448
	−0.1	*0.4*	*0.4*	*0.1*	*−0.1*	*−0.9*	*−0.4*	*−0.2*	*−0.2*	*−0.1*	*0.2*	*0.3*	*1.2*	*−0.5*	*−0.7*
Unemployment rate	7.6	7.8	7.6	7.9	8.8	9.4	9.6	9.9	10.2	10.3	10.3	10.0	7.7	9.4	10.2
Retail sales (current $)	12,213	12,112	12,438	11,879	11,937	12,203	12,330	12,445	12,477	12,550	12,642	12,741	12,160	12,228	12,603
	3.4	*−0.8*	*2.7*	*−4.5*	*0.5*	*2.2*	*1.0*	*0.9*	*0.3*	*0.6*	*0.7*	*0.8*	*4.5*	*0.6*	*3.1*
Housing starts (units)	4,744	3,798	3,980	3,406	3,738	3,191	3,017	3,009	3,041	3,045	3,016	3,046	3,982	3,239	3,037
	1.5	*−20.0*	*4.8*	*−14.4*	*9.8*	*−14.7*	*−5.5*	*−0.3*	*1.0*	*0.1*	*−1.0*	*1.0*	*−16.2*	*−18.7*	*−6.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

New Brunswick

- Tax cuts and infrastructure spending will prevent the economy from sliding into recession.
- The boom in the construction industry is over.

Real GDP

	Growth	Ranking
2009	0.5	#2
2010	2.2	#6

Credit Quality

AA–

Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–0.6	#3
2010	4.5	#3

Government & Background Information

Premier	Shawn Graham
Next election	2010
Population (2009:1)	748,319
Government balance (2009–10)	–$741 million

Source: The Conference Board of Canada.

Bold Fiscal Plan Helps Province Avert Recession

by Prince Owusu

Amid growing fears that the province was slipping into recession, the provincial government announced a bold economic rescue plan—a $1.2-billion infrastructure program and $402 million in tax cuts over the next two fiscal years. New Brunswick will outperform the national average this year, with real gross domestic product gaining 0.5 per cent. That will be good enough for second place among the 10 provinces.

The boom in the province's construction industry came to an end last year with the completion of major construction works. The development of the $1.7-billion PotashCorp mine and processing facility and the government's infrastructure program spending will not be enough to completely fill the void left by the completion of over $2 billion worth of construction work involving the Canaport liquefied natural gas (LNG) terminal and associated pipeline and the Point Lepreau nuclear plant refurbishment.

The forestry sector continues to be challenged by the downturn in the housing sector south of the border. Until the U.S. housing sector begins to recover, prospects will not be encouraging for forestry-related activities in the province. Weak demand for lobster—a luxury food item that consumers often go without in recessionary periods—will also hurt New Brunswick's seafood processing industry. With commodity prices languishing, the mining industry is not expected to recover until demand conditions improve next year.

As job losses mount, retail sales are expected to contract by 0.6 cent in 2009. Patronage at restaurants and amusement centres and spending on personal services are expected to be restrained this year as households' income prospects deteriorate. Next year—with the U.S. recovery under way—industrial production in New Brunswick is expected to pick up. In addition, design and engineering activities for Irving Oil's second gasoline refinery will help boost business services, allowing real GDP to advance by 2.2 per cent in 2010.

CONSTRUCTION INDUSTRY TAKES A BREATHER

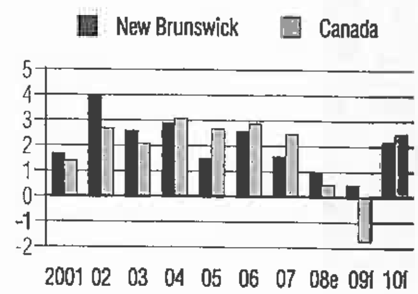
The construction industry, which has been the lifeline of the economy over the past four years, will lose much of its vigour this year. For starters, construction of new homes is expected to plummet by an average of 19.8 per cent over the next two years as the job market loses steam and household income dwindles. With the

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	0.1	0.5	2.2
Consumer Price Index	1.7	0.1	2.4
Personal disposable income	4.7	2.2	3.9
Employment	0.9	–0.2	0.3
Unemployment rate (level)	8.6	9.7	10.8
Retail sales	4.8	–0.6	4.5
Average weekly wages	2.6	1.2	2.6
Population	0.2	0.2	0.2

Sources: The Conference Board of Canada; Statistics Canada.

Stronger **Growth in New Brunswick**
(real GDP, percentage change)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

housing market lining up closer to demographic requirements, housing starts are forecast to drop to 2,750 units by 2010, down from 4,274 units in 2008. As a result, residential investment is forecast to decline by an average of 10.6 per cent—or a total of $350 million—over 2009–10, the first contraction in a decade.

Construction of new homes is expected to plummet by an average of 19.8 per cent over the next two years as the job market loses steam.

The completion of work on the concrete vault of the Point Lepreau nuclear plant refurbishment and on the Canaport LNG plant and its associated pipeline will reduce private and public non-residential construction investment spending by nearly $2 billion this year. As a result, real construction output is expected to decline by an average of 5.6 per cent over 2009–10.

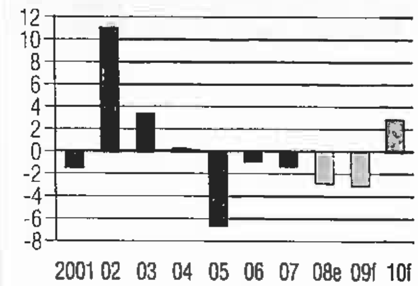
Other initiatives, however, will keep the industry from sinking deeper. PotashCorp has begun work on a $1.7-billion expansion of its plant near Sussex. The project is expected to generate 2,500 person-years of employment during the construction period and 140 new full-time positions upon completion of the project in 2011. In addition, the provincial government is expected to spend $1.2 billion over the next two years on infrastructure projects across the province to help insulate the economy against the global recession. There are also several wind farm developments totalling $200 million in investment. Without these projects providing the needed offset, the construction industry would lose more than 2,633 jobs over 2009–10.

DEMAND FOR FORESTRY PRODUCTS TUMBLES

The demise of the forestry sector (along with weak demand for seafood products) will hit the manufacturing industry hard this year. Housing starts in the U.S. fell below the one-million mark last year for the first time since record-keeping began, and starts are expected to average 592,000 units per year over 2009–10. The drop will dampen demand for lumber products, one of New Brunswick's major export commodities.

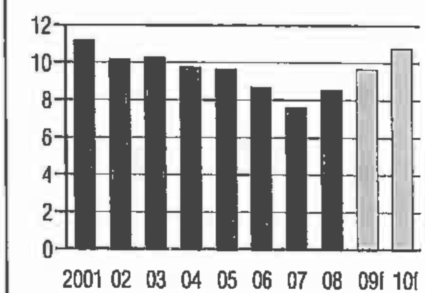
With the U.S economy still struggling, and with several print media companies folding, demand for pulp and paper for advertising purposes, paperboard containers, paper bags, and other wood-related

Manufacturing Sector Still Declining
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Unemployment Rate Moves Higher
(per cent)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

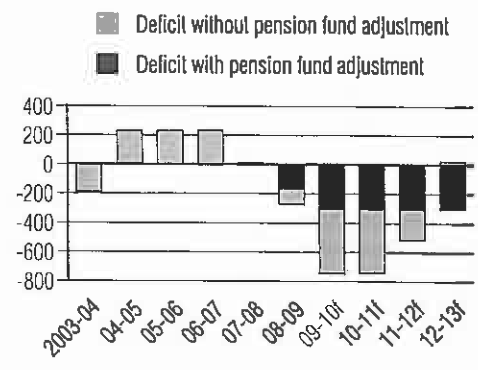
Record Deficit Causes Provincial Debt to Balloon

The days of budget surpluses are over in New Brunswick—at least for the next four fiscal years. A $265-million deficit for fiscal year 2008–09 ended four years of surpluses totalling $723 million. The 2009–10 budget features an expansive plan to pull the economy out of the throes of recession. A record $1.2-billion, two-year infrastructure plan is expected to boost the economy and create 6,000 persons-years of employment. In addition to the record government investment, personal income taxes have been reduced—a tax savings for consumers worth more than $1 billion over four years. The new jobs and improved disposable income from the tax savings will stimulate demand and help prevent the economy from sliding into recession.

All these measures come at a long-term price—the largest deficit ever seen in the history of the province. A weaker economy failing to generate adequate revenues, public sector pension fund shortfalls, and ground-breaking investment strategies will all combine to leave the province with a deficit totalling $2.3 billion over the next four fiscal years. Financing the deficit will send the provincial government deeper into debt for years to come. Net debt, which stood at $6.9 billion in 2008, is expected to balloon to $8.3 billion by 2010.

It is important to mention, however, that the deficit includes $300 million a year in public sector pension fund adjustments that may not be required once conditions in the financial market improve and the funds begin to make adequate return. If this scenario pans out, the provincial government anticipates balancing the books by 2012–13.

Provincial Deficit Balloons
($ millions)



f = forecast
Sources: Provincial Public Accounts; New Brunswick's 2009–10 Budget.

products will wane this year. Lower royalty rates and generous incentives have not been enough to prevent the closing of saw and pulp mills throughout the province over the last few years. The shutdowns are spreading beyond the forestry industry. McCain Foods has reduced production at its Grand Falls and Florenceville facilities, a chemical plant in Dalhousie is expected to close this summer, and a glass bottle plant in Scoudouc closed last year. (The fallout from the closure of the glass bottle plant has spread beyond the 200 laid-off workers, since the province's beverage industry relied on the plant for its supply of bottles.) Also on the downside, the province's largest manufacturing plant—the Irving gasoline refinery—has reached capacity and will not provide much stimulus to manufacturing.

Irving Oil is expected to begin re-gasification of liquid natural gas at its new Canaport facility in the second half of this year.

On the positive side, Irving Oil is expected to begin re-gasification of liquid natural gas at its new Canaport facility in the second half of this year. The value added through re-gasification will help minimize the contraction of manufacturing output to only 3 per cent this year. Also, the Canadian dollar has fallen from a high of US$1.09 in November 2007 to between US$0.80 and US$0.85 recently. We expect the dollar to average US$0.80 over 2009–10. With the weaker loonie loosening its grip on exporters, and the U.S. economy slowly recovering, real manufacturing output is projected to rebound by 2.9 per cent next year.

DOMESTIC DEMAND OUTLOOK

New Brunswick's economy is feeling the pinch of the global financial crisis. With demand south of the border faltering and the provincial economy failing to generate jobs, the unemployment rate has started creeping up. After dropping to 7.6 per cent in 2007 (the lowest since record keeping began), the jobless rate is expected to average 10.2 per cent over 2009–10, or 1.4 percentage points higher than the national average. Along with the dismal job market outlook, wage gains will slow as the provincial government freezes wages for its workers and companies engage in cost-cutting and efficiency measures in a bid to stay competitive in this challenging economic environment.

With employment prospects bleak and household income weakening, consumer sentiments are at their lowest ebb in the Atlantic region—and retail sales have been very weak in recent months. Nevertheless, a drop of only 0.6 per cent is expected this year thanks to the $365.4 million in personal income tax cuts provided by the provincial government. A quick rebound of 4.5 per cent is forecast for retail sales next year.

The poor outlook for the job market will lead many New Brunswickers to curtail expenditures on amusement and recreation activities and at restaurants. Not only are New Brunswickers cutting back spending, the number of tourists visiting the province plummeted last year—and things will likely get worse this year as global economic conditions deteriorate. As a result, real output in the accommodation and food and industry is expected to contract by 0.4 per cent before rebounding to 2 per cent next year along with the general improvement in the economy.

With the forestry and manufacturing sectors still on their knees, less cargo is expected to pass through the province's ports. Growth in the transportation and warehousing industry is expected to contract by 0.3 per cent over 2009–10.

Forecast Risks

Short term

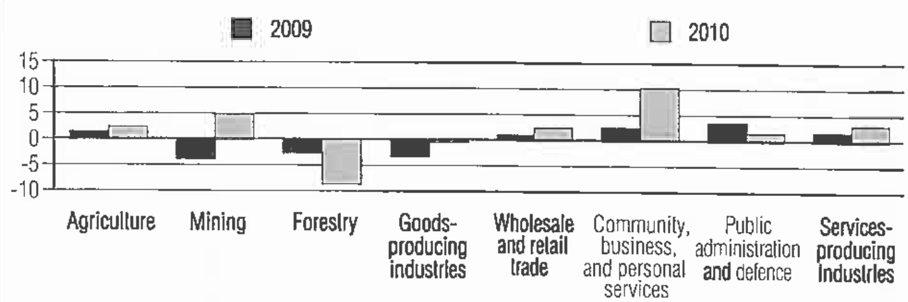
- A rapid appreciation of the Canadian dollar would spell further bad news for manufacturers.

Medium term

- The twinning of Route 11 could bolster construction activities.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Source: The Conference Board of Canada.

Key Economic Indicators: New Brunswick
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	27,578 *1.4*	28,362 *2.8*	28,544 *0.6*	27,827 *−2.5*	27,365 *−1.7*	27,395 *0.1*	27,636 *0.9*	28,017 *1.4*	28,369 *1.3*	28,552 *0.6*	28,837 *1.0*	29,213 *1.3*	28,078 *4.2*	27,603 *−1.7*	28,743 *4.1*
GDP at basic prices (current $)	25,439 *2.0*	26,204 *3.0*	26,390 *0.7*	25,733 *−2.5*	25,289 *−1.7*	25,327 *0.2*	25,548 *0.9*	25,903 *1.4*	26,219 *1.2*	26,370 *0.6*	26,616 *0.9*	26,950 *1.3*	25,941 *4.9*	25,517 *−1.6*	26,538 *4.0*
GDP at basic prices (constant $ 2002)	21,442 *−0.6*	21,622 *0.8*	21,638 *0.1*	21,567 *−0.3*	21,617 *0.2*	21,626 *0.0*	21,676 *0.2*	21,762 *0.4*	21,921 *0.7*	22,050 *0.6*	22,209 *0.7*	22,399 *0.9*	21,567 *1.0*	21,670 *0.5*	22,145 *2.2*
Consumer Price Index (2002 = 1.0)	1.118 *0.1*	1.137 *1.7*	1.146 *0.8*	1.124 *−1.9*	1.118 *−0.5*	1.131 *1.2*	1.138 *0.6*	1.145 *0.6*	1.151 *0.5*	1.157 *0.6*	1.164 *0.6*	1.171 *0.7*	1.131 *1.7*	1.133 *0.1*	1.161 *2.4*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.186 *2.6*	1.212 *2.1*	1.220 *0.6*	1.193 *−2.2*	1.170 *−2.0*	1.171 *0.1*	1.179 *0.6*	1.190 *1.0*	1.196 *0.5*	1.196 *0.0*	1.198 *0.2*	1.203 *0.4*	1.203 *3.9*	1.177 *−2.1*	1.198 *1.8*
Average weekly wages (**$**, industrial composite)	677.1 *0.0*	684.7 *1.1*	690.2 *0.8*	689.8 *−0.1*	691.7 *0.3*	691.2 *−0.1*	693.7 *0.4*	697.9 *0.6*	704.6 *1.0*	709.3 *0.7*	714.1 *0.7*	718.9 *0.7*	685.5 *2.6*	693.6 *1.2*	711.7 *2.6*
Personal income (current $)	23,158 *2.2*	23,253 *0.4*	23,349 *0.4*	23,553 *0.9*	23,504 *−0.2*	23,610 *0.5*	23,770 *0.7*	23,951 *0.8*	24,200 *1.0*	24,382 *0.8*	24,611 *0.9*	24,858 *1.0*	23,328 *4.4*	23,709 *1.6*	24,513 *3.4*
Personal disposable income (current $)	18,479 *2.5*	18,645 *0.9*	18,748 *0.6*	18,912 *0.9*	18,919 *0.0*	19,020 *0.5*	19,152 *0.7*	19,301 *0.8*	19,593 *1.5*	19,757 *0.8*	19,937 *0.9*	20,121 *0.9*	18,696 *5.3*	19,098 *2.2*	19,852 *3.9*
Personal savings rate	2.00	1.09	−0.49	2.14	2.15	1.45	1.09	0.96	1.23	1.55	1.80	1.98	1.19	1.41	1.64
Population of labour force age (000s)	616 *0.2*	618 *0.2*	619 *0.2*	619 *0.1*	620 *0.1*	621 *0.1*	622 *0.1*	623 *0.2*	624 *0.2*	625 *0.2*	626 *0.1*	627 *0.1*	618 *0.8*	622 *0.6*	625 *0.6*
Labour force (000s)	400 *0.8*	400 *0.1*	400 *−0.1*	403 *0.7*	402 *−0.1*	404 *0.4*	405 *0.4*	407 *0.4*	409 *0.5*	410 *0.2*	411 *0.1*	412 *0.4*	401 *2.0*	405 *1.0*	411 *1.4*
Employment (000s)	366 *0.0*	364 *−0.5*	366 *0.5*	368 *0.4*	366 *−0.4*	365 *−0.2*	365 *−0.1*	365 *−0.1*	365 *0.1*	366 *0.1*	366 *0.1*	368 *0.7*	366 *0.9*	365 *−0.2*	366 *0.3*
Unemployment rate	8.4	8.9	8.4	8.7	9.0	9.5	10.0	10.4	10.7	10.9	10.8	10.6	8.6	9.7	10.8
Retail sales (current $)	9,576 *0.8*	9,765 *2.0*	10,074 *3.2*	9,665 *−4.1*	9,438 *−2.3*	9,696 *2.7*	9,812 *1.2*	9,907 *1.0*	10,040 *1.3*	10,107 *0.7*	10,174 *0.7*	10,274 *1.0*	9,770 *4.8*	9,713 *−0.6*	10,149 *4.5*
Housing starts (units)	5,300 *41.7*	4,233 *−20.1*	3,830 *−9.5*	3,734 *−2.5*	3,637 *−2.6*	3,409 *−6.3*	3,376 *−1.0*	3,156 *−6.5*	2,847 *−9.8*	2,767 *−2.8*	2,631 *−4.9*	2,756 *4.8*	4,274 *0.8*	3,394 *−20.6*	2,750 *−19.0*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Quebec

- Downsizing in labour markets puts the freeze on real consumption expenditures this year.
- The only sector that will contribute greatly to the economy is government, mainly through its infrastructure programs.

Real GDP

	Growth	Ranking
2009	–0.9	#6
2010	1.8	#7

Credit Quality
A+
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–2.3	#6
2010	3.9	#6

Government & Background Information

Premier	Jean Charest
Next election	2012
Population (2009:1)	7,782,561
Government balance (2009–10)	–$3.9 billion

Sources: Quebec Finance; Statistics Canada.

A "Mild" Recession

by Marie-Christine Bernard

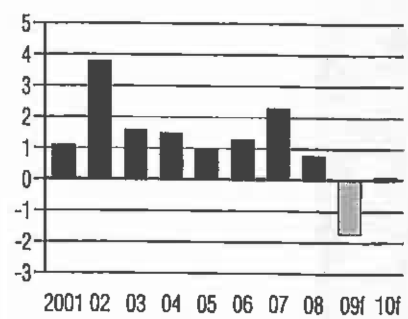
While an economic slump is never good news for businesses or households, the global economic storm has not affected Quebec nearly as much as it has Ontario, Alberta, and British Columbia. Nevertheless, Quebec still faces a recession, though not as severe as the 1981–82 and 1990–91 downturns. Overall real GDP at market prices is forecast to slide by 0.9 per cent in 2009. While most sectors will face major drops this year, the province will get a big boost from public infrastructure development. The province has been upgrading heavily its infrastructure over the past few years, and this trend will continue unabated in 2009–10.

The manufacturing sector is going to remain weak until the end of the year. The aerospace industry is facing dim prospects this year. Order cancellations and deferrals for its business jets and a lack of credit financing have forced Bombardier to slash production and lay off more than 1,700 workers in Montréal. At the same time, the company will proceed with its CSeries line of medium-range jetliners. Engineers and technicians will be needed, offsetting some of the downfall. For the most part, businesses and households will be reluctant to spend this year, keeping real consumption expenditures at a standstill and private investment at a depressed level. Without a doubt, the first half of 2009 has been, and will continue to be, challenging. The provincial government is forecasting a $3.9 billion shortfall for this fiscal year. Fuelled by federal fiscal stimulus, a modest turnaround in the U.S. economy, and rock-bottom interest rates, real gross domestic product growth is expected to resume in the second half of the year. The province is forecast to bounce back with growth of 1.8 per cent in 2010. Positive export and capital investment growth is forecast for next year. The need to hire additional workers will lag the economic recovery, and the unemployment rate is expected to reach 9.8 per cent by the end of 2010.

HELP WANTED ADS DISAPPEARING

Labour markets are reacting to the economic downturn. More than 55,000 workers have lost their jobs since October 2008. The unemployment rate hit 8.3 per cent in March—a 1.1 percentage-point hike in just six months. Since the start of the year, the manufacturing, transportation and warehousing, accommodation, and food services industries have been slashing payrolls, as have the information, cultural, and recreation industries. Part-time and full-time positions have been eliminated, and most worrisome is the rising trend in self-employment. On an annual basis, 68,000 jobs will disappear this year, and no significant job creation is expected before the economic recovery is in full swing in 2011. Laid-off workers will

Labour Pains
(employment, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	1.0	–0.9	1.8
Consumer Price Index	2.1	0.5	2.7
Personal disposable income	4.9	0.5	3.0
Employment	0.8	–1.7	0.1
Unemployment rate (level)	7.3	8.8	9.8
Retail sales	4.8	–2.3	3.9
Average **weekly wages**	2.9	1.6	2.5
Population	0.8	0.7	0.5

Sources: The Conference Board of Canada; Statistics Canada.

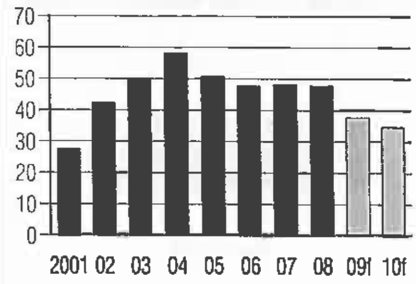
continue to search for work, boosting the labour force and the unemployment rate to an average of 8.8 per cent in 2009 and 9.8 per cent in 2010.

Real incomes will show little growth this year. After advancing by an average of 4.4 per cent in the past two years, real disposable income growth of just 0.5 per cent is expected in 2009. The latest provincial budget did not provide much in terms of stimulus for households. The federal budget was more generous. It introduced several permanent, broad-based tax cuts and credits targeted at providing assistance to low- and middle-income Canadians, who are disproportionately affected by the economic downturn. From 2010 onward, these initiatives will be indexed to inflation. There is some encouraging news for retailers—consumer confidence in Quebec is slowly rebounding. Real consumption expenditures—which had risen strongly since 2002—are forecast to grow by just 0.2 per cent in 2009 and 1.7 per cent in 2010. Real durable goods consumption will be the most affected, with a drop of 3.9 per cent forecast in 2009.

LULL IN INVESTMENT

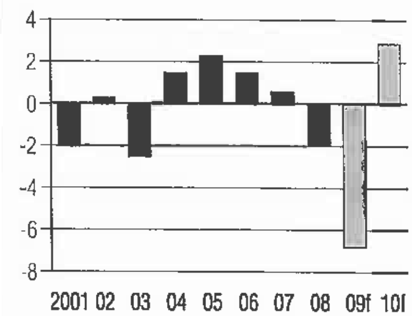
The credit crisis, low base metal prices, and deteriorating economic conditions since the start of the year have dampened investment intentions. According to Statistics Canada's Survey of Private and Public Investment Intentions, non-residential investment will retreat in the manufacturing sector and, more importantly, in the mining industry in 2009. Luckily, investment in the energy sector will shield the province to a certain degree from the global economic difficulties. A number of major developments in the electricity sector will proceed as planned. Among the major projects under way are Hydro-Québec's $5-billion Eastmain-1-A-Sarcelle-Rupert project, the work to increase transmission capacity with the Ontario electricity grid, and new wind farm projects by Northland Power and Carter énergie éolienne. In addition, Hydro-Québec has some additional major projects planned, including the $6.5-billion La Romaine project and the upgrade of the Gentilly 2 nuclear station, both of which are expected to get under way in the near term. Nevertheless, total real non-residential investment is expected to decline by 6.8 per cent in 2009. The outlook for investment in 2010 is positive as several commercial projects are planned. Aluminum processing plant upgrades by Rio Tinto Alcan in Saguenay–Lac-Saint-Jean ($650 millions) and by Alcoa in the Côte-Nord ($1.2 billion) will also boost investment in the province. Growth of 8.8 per

Recession and Demographics Hurt Housing
(housing starts, units, 000s)



f = forecast
Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

A Difficult Year for Exporters
(real exports, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Budget Deficits Unavoidable

Quebec's fiscal situation will be challenged by the recession. A $3.9-billion deficit is expected this fiscal year, and a $3.7 shortfall is projected for 2010–11. While the 2009 budget did not provide a lot of new economic stimulus, infrastructure plans announced previously will greatly stimulate the province. In total, $42 billion has been earmarked for infrastructure between 2008 and 2013. This fiscal year, $8.3 billion will be spent on public capital projects compared with about $5 billion in fiscal 2008-09. Growth in nominal program spending will be limited to 4.5 per cent in 2009–10 and 3.2 per cent in 2010–11. There will be no interruptions in payments to the Generations Fund, with the fund's value reaching $3.5 billion by March 2011.

Total revenues are expected to decline by 0.4 per cent in 2009–10 before recovering with modest 2.9 per cent growth in 2010–11. At a time when slower economic growth impinges on revenue collections, Quebec has prudently opted to increase the provincial sales tax by one percentage point, starting in 2011. Careful offset has been provided to low-income families in the form of enhanced sales tax rebates and $500 million in increased funding to the Employment Pact over three years. A return to fiscal balance will be the major challenge facing Quebec in the years ahead. With cumulative deficits of $11.6 billion in the cards over the next four years and a ballooning provincial debt (the most burdensome in Canada), a return to balanced budgets is not planned before 2013-14. The province's net debt as a share of GDP is expected to escalate from 42.8 per cent this year to 46.3 per cent by 2011! By 2010–11, Quebec's net debt will reach a troubling $145 billion.

cent is expected for total non-residential investment next year.

The outlook for machinery and equipment is grim. Falling corporate profits, struggling manufacturers, and a depreciating currency will pull real machinery and equipment spending down by 15.7 per cent in 2009. Despite the negative outlook, some industries are charging ahead with major expansions. Machinery and equipment investment in the petroleum and coal products industry will more than double in 2009. As well, Vidéotron's Internet wireless systems and Bell's telephone services are also being upgraded.

The provincial government will continue to invest heavily in infrastructure. Public investment represents over 70 per cent of all non-residential investment in the province, a situation not seen since 1970. According to the Commission de la construction du Québec, civil engineering workers should see their hours-worked jump by 12 per cent this year—the same increase as last year. Public investment will progress strongly in the next few years, with the provincial government having promised to invest $37.7 billion between fiscal years 2008 and 2013. Early this year, the provincial government announced that it would hike the planned spending by $4.1 billion for a total of $41.8 billion. Several highway expansions are planned, as are new health-care facilities. In addition, the province will get a boost from the recent federal budget. After robust performances in the last couple of years, real public capital expenditures will rise 21.3 per cent in 2009. The boom will persist in 2010, with growth in public capital expenditures of 7.6 per cent.

HOUSING DRAGGED DOWN

The housing market will lose steam this year. The current economic downturn will suppress demand. Also, the housing market had been developing at an unsustainable pace given the demographic make up of the province. A correction will realign housing construction closer to actual demographic requirements. The Quebec housing market was still healthy at the start of the year (in contrast to what we've seen in Western Canada). Nevertheless, housing starts are forecast to tumble to 37,760 units in 2009 (down 21.2 per cent) and to 34,782 units in 2010. Real residential investment is forecast to drop 5.4 per cent in 2009 in spite of federal renovation incentives. A larger 9.2 per cent decline is forecast for next year.

EXPORTS IN A MAJOR SLUMP

With the U.S.—Canada's biggest trading partner—in economic turmoil, exports have been declining. The worst is not over. Real exports are forecast to drop by 6.8 per cent in 2009, the largest reduction in trade activity since the early 1980s. It will be difficult for most exporters in the province. Prospects are grim for the information and technology products, forestry, primary metals and pulp and paper industries. Until a bottom is formed in the housing industry and in consumption south of the border, no turnaround is expected in those sectors. While new business opportunities in the U.S. are limited, manufacturers in the province are starting to focus more on emerging markets that are still growing. Also, as governments around the world step up public infrastructure spending as part of their anti-recession efforts, new opportunities will arise for suppliers of building materials, fabricated metal, primary metals, and engineering services over the next two year.

The aerospace industry, the most important export sector is starting to feel the global economic turbulence. In February, Bombardier announced that it was reducing production of its Learjet and Challenger aircrafts, a move that will affect about 710 permanent and contract workers in the province over the next year. The company announced a second round of layoffs in April, with an additional 1,030 workers to lose their jobs in the Montréal region. Bombardier expects to deliver 25 per cent fewer business aircraft this fiscal year. At the same time, however, it will increase deliveries of its commercial aircraft by 10 per cent. Bombardier will fill 730 permanent positions in Montréal to work on the company's CSeries and Learjet 85 aircraft, and at its Global aircraft completion centre. Looking to 2010, a slowly recovering U.S. economy, coupled with a more stable loonie, will help boost total exports by 2.9 per cent.

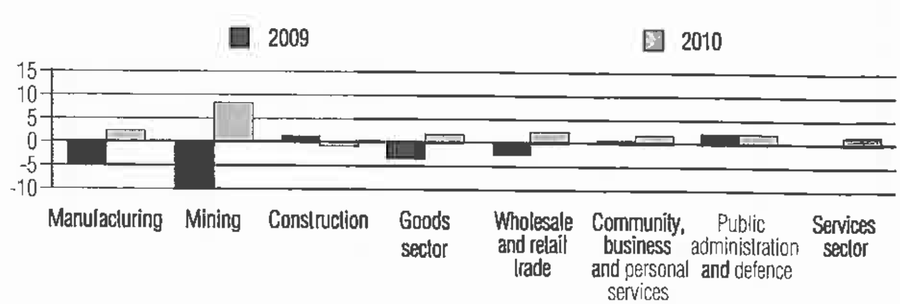
Forecast Risks

Short term
- If public infrastructure projects are delayed, the economy could sink deeper into recession.

Medium term
- A return to fiscal deficits may limit the provincial government's contribution to the economy in the next few years.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Quebec
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	300,809	306,129	308,545	302,233	298,880	297,494	299,834	303,333	306,485	307,757	309,937	313,131	304,429	299,885	309,327
	0.2	*1.8*	*0.8*	*−2.0*	*−1.1*	*−0.5*	*0.8*	*1.2*	*1.0*	*0.4*	*0.7*	*1.0*	*2.6*	*−1.5*	*3.1*
GDP at basic prices (current $)	282,768	287,928	290,378	284,565	281,372	280,050	282,218	285,499	288,348	289,352	291,199	294,042	286,410	282,285	290,735
	0.6	*1.8*	*0.9*	*−2.0*	*−1.1*	*−0.5*	*0.8*	*1.2*	*1.0*	*0.3*	*0.6*	*1.0*	*3.0*	*−1.4*	*3.0*
GDP at basic prices (constant $ 2002)	247,025	247,560	248,341	247,381	246,527	244,610	244,866	245,566	247,928	248,947	250,179	251,804	247,577	245,392	249,714
	0.2	*0.2*	*0.3*	*−0.4*	*−0.3*	*−0.8*	*0.1*	*0.3*	*1.0*	*0.4*	*0.5*	*0.6*	*1.0*	*−0.9*	*1.8*
Consumer Price Index (2002 = 1.0)	1.114	1.134	1.139	1.124	1.121	1.130	1.137	1.145	1.153	1.159	1.167	1.175	1.127	1.133	1.163
	0.5	*1.8*	*0.4*	*−1.3*	*−0.2*	*0.8*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*2.1*	*0.5*	*2.7*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.145	1.163	1.169	1.150	1.141	1.145	1.153	1.163	1.163	1.162	1.164	1.168	1.157	1.150	1.164
	0.4	*1.6*	*0.5*	*−1.6*	*−0.8*	*0.3*	*0.7*	*0.9*	*0.0*	*−0.1*	*0.1*	*0.3*	*2.1*	*−0.6*	*1.2*
Average weekly wages (**$**, industrial composite)	719.4	723.9	729.2	736.4	737.1	736.5	738.9	743.2	750.2	755.0	759.9	764.8	727.2	738.9	757.5
	0.8	*0.6*	*0.7*	*1.0*	*0.1*	*−0.1*	*0.3*	*0.6*	*0.9*	*0.6*	*0.6*	*0.6*	*2.9*	*1.6*	*2.5*
Personal income (current $)	258,450	258,535	259,558	261,353	259,449	259,281	260,575	262,630	265,431	267,571	270,268	272,462	259,474	260,483	268,933
	2.1	*0.0*	*0.4*	*0.7*	*−0.7*	*−0.1*	*0.5*	*0.8*	*1.1*	*0.8*	*1.0*	*0.8*	*3.8*	*0.4*	*3.2*
Personal disposable income (current $)	197,151	198,036	199,006	200,428	198,723	198,680	199,662	201,244	202,969	204,770	206,679	208,193	198,655	199,577	205,652
	2.9	*0.4*	*0.5*	*0.7*	*−0.9*	*0.0*	*0.5*	*0.8*	*0.9*	*0.9*	*0.9*	*0.7*	*5.5*	*0.5*	*3.0*
Personal savings rate	2.95	2.33	1.92	3.75	3.80	3.07	2.72	2.60	2.82	3.05	3.39	2.96	2.74	3.05	3.065
Population of labour force age (000s)	6,349	6,364	6,380	6,396	6,411	6,423	6,436	6,455	6,460	6,472	6,485	6,497	6,372	6,431	6,478
	0.2	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.3*	*0.1*	*0.2*	*0.2*	*0.2*	*0.9*	*0.9*	*0.7*
Labour force (000s)	4,183	4,186	4,180	4,192	4,178	4,167	4,182	4,200	4,216	4,226	4,238	4,249	4,185	4,182	4,232
	0.2	*0.1*	*−0.1*	*0.3*	*−0.4*	*−0.3*	*0.4*	*0.4*	*0.4*	*0.2*	*0.3*	*0.2*	*0.9*	*−0.1*	*1.2*
Employment (000s)	3,888	3,877	3,869	3,889	3,845	3,811	3,799	3,799	3,803	3,810	3,819	3,833	3,881	3,813	3,816
	0.1	*−0.3*	*−0.2*	*0.5*	*−1.1*	*−0.9*	*−0.3*	*0.0*	*0.1*	*0.2*	*0.2*	*0.4*	*0.8*	*−1.7*	*0.1*
Unemployment rate	7.1	7.4	7.4	7.2	8.0	8.5	9.2	9.6	9.8	9.8	9.9	9.8	7.3	8.8	9.8
Retail sales (current $)	93,718	95,626	96,973	93,955	90,744	92,686	93,625	94,588	95,192	95,921	96,643	98,212	95,068	92,911	96,492
	2.1	*2.0*	*1.4*	*−3.1*	*−3.4*	*2.1*	*1.0*	*1.0*	*0.6*	*0.8*	*0.8*	*1.6*	*4.8*	*−2.3*	*3.9*
Housing starts (units)	48,096	48,195	49,212	46,101	41,503	37,360	36,190	35,988	35,674	35,695	34,739	33,020	47,901	37,760	34,782
	21.1	*0.2*	*2.1*	*−6.3*	*−10.0*	*−10.0*	*−3.1*	*−0.6*	*−0.9*	*0.1*	*−2.7*	*−4.9*	*−1.3*	*−21.2*	*−7.9*

While area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Québec

- La contraction du marché du travail bloque les dépenses de consommation réelle cette année.
- Le seul secteur qui contribuera largement à l'économie est l'administration publique, principalement grâce à ses programmes d'infrastructure.

PIB réel

	Croissance	Classement
2009	–0,9	nº 6
2010	1,8	nº 7

Qualité du crédit
A+
Standard & Poor's

Ventes au détail

	Croissance	Classement
2009	–2,3	nº 6
2010	3,9	nº 6

Renseignements généraux

Premier ministre	Jean Charest
Prochaines élections	2012
Population (2009:1)	7 782 561
Solde du secteur public (2009–2010)	–3,9 milliards $

Sources : Ministère des Finances du Québec; Statistique Canada.

Une récession « légère »

par Marie-Christine Bernard

LA DISPARITION DES OFFRES D'EMPLOI

Le marché du travail réagit à l'effondrement économique. Plus de 55 000 travailleurs ont perdu leur emploi depuis octobre 2008. Le taux de chômage a grimpé jusqu'à 8,3 p. 100 en mars — une augmentation de 1,1 point de pourcentage en tout depuis juste six mois. Depuis le début de l'année, l'industrie manufacturière et les secteurs des transports, de l'entreposage, de l'hébergement et de la restauration ont fait des coupes sombres dans leurs effectifs, tout comme les industries de l'information, de la culture et des loisirs.

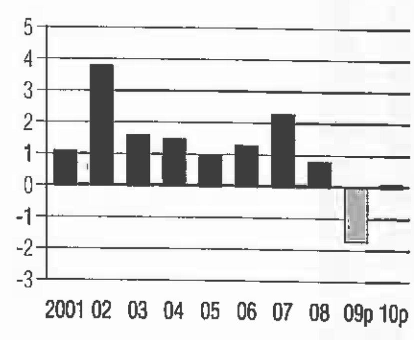
Des postes à temps partiel et à temps plein ont été supprimés et, ce qui est des plus inquiétant, la tendance à se lancer dans le travail indépendant est de plus en plus marquée. Sur une base annuelle, 68 000 emplois disparaîtront cette année et on ne compte sur aucune création d'emplois significative tant que l'économie ne battra pas à nouveau son plein en 2011. Les travailleurs mis à pied continueront de chercher du travail, ce qui portera le taux de chômage jusqu'à une moyenne de 8,8 p. 100 en 2009 et de 9,8 p. 100 en 2010.

La croissance des revenus réels sera faible cette année. Après avoir progressé de 4,4 p. 100 en moyenne ces deux dernières années, la croissance du revenu disponible réel devrait s'élever à tout juste 0,5 p. 100 en 2009. Le dernier budget provincial n'a pas prévu beaucoup de stimulants pour les ménages. Mais le budget fédéral a été plus généreux. Il a instauré plusieurs réductions et crédits d'impôts généralisés permanents à l'intention des Canadiens à revenu faible et moyen, qui souffrent de façon disproportionnée de l'effondrement économique. À partir de 2010, ces mesures seront indexées sur l'inflation. Il y a aussi quelques nouvelles encourageantes pour les détaillants — la confiance renaît lentement chez les consommateurs québécois. Les dépenses de consommation réelle — qui avaient fortement augmenté depuis 2002 — devraient normalement croître de tout juste 0,2 p. 100 en 2009 et 1,7 p. 100 en 2010. La consommation réelle de biens durables sera frappée le plus durement, une baisse de 3,9 p. 100 étant prévue en 2009.

LES INVESTISSEMENTS SOMMEILLENT

La crise du crédit, la faiblesse des prix des métaux de base et la détérioration des conditions économiques depuis le début de l'année ont eu pour effet de réfréner les intentions d'investissement. Selon l'Enquête sur les intentions d'investissement des secteurs

Difficultés du marché de l'emploi
(emploi, variation en pourcentage)



p = prévisions
Sources : Le Conference Board du Canada; Statistique Canada.

Indicateurs économiques
(en dollars de 2002; variation en pourcentage)

	2008	2009	2010
PIB réel (aux prix de base)	1.0	–0.9	1.8
Indice des prix à la consommation	2.1	0.5	2.7
Revenu personnel disponible	4.9	0.5	3.0
Emploi	0.8	–1.7	0.1
Taux de chômage	7.3	8.8	9.8
Ventes au détail	4.8	–2.3	3.9
Salaires hebdomadaires moyens	2.9	1.6	2.5
Population	0.8	0.7	0.5

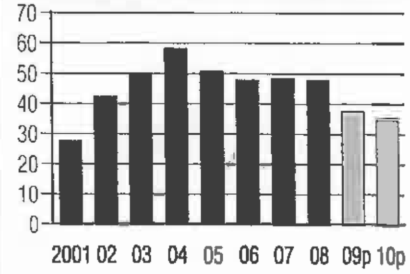
Sources : Le Conference Board du Canada; Statistique Canada.

privé et public de Statistique Canada, les investissements non résidentiels reculeront en 2009 dans le secteur manufacturier et, ce qui est encore plus important, dans l'industrie minière. Heureusement, ceux effectués dans le secteur de l'énergie protégeront la province jusqu'à un certain point contre les difficultés économiques mondiales. Quelques grands projets de développement du secteur électrique se poursuivront comme prévu. Parmi ceux déjà en cours, il y a le projet d'Eastmain-1-A-Sarcelle-Rupert de 5 milliards de dollars d'Hydro-Québec, les travaux visant à augmenter la capacité de transmission au réseau ontarien de distribution d'électricité et les nouveaux projets de construction d'éoliennes de Northland Power et de Cartier énergie éolienne. De plus, Hydro-Québec prévoit quelques grands projets supplémentaires, dont celui de La Romaine, de 6,5 milliards de dollars, et l'amélioration de la centrale nucléaire de Gentilly-2, qui devraient tous deux être mis en chantier prochainement. En 2009, on s'attend, néanmoins, à une baisse de 6,8 p. 100 du total des investissements non résidentiels réels. Les perspectives d'investissement pour 2010 sont positives du fait que plusieurs projets commerciaux sont prévus. Les travaux de modernisation entrepris par Rio Tinto Alcan dans les usines de traitement de l'aluminium du Saguenay–Lac-Saint-Jean (650 millions de dollars) et par Alcoa sur la Côte-Nord (1,2 milliard de dollars) donneront également un coup d'accélérateur aux investissements de la province. Pour l'an prochain, on s'attend à une croissance de 8,8 p. 100 du total des investissements non résidentiels.

Pour les machines et le matériel, les perspectives sont maussades. La baisse des bénéfices des sociétés, les difficultés des manufacturiers et la dépréciation du dollar canadien se traduiront, en 2009, par un effondrement des dépenses réelles en machines et matériel de 15,7 p. 100. Malgré ces perspectives négatives, quelques industries progressent à toute allure avec de grands travaux de développement. Les investissements en machines et matériel de l'industrie des produits du pétrole et du charbon feront plus que doubler en 2009. De plus, les systèmes Internet sans fil de Vidéotron et les services téléphoniques de Bell sont également en cours de modernisation.

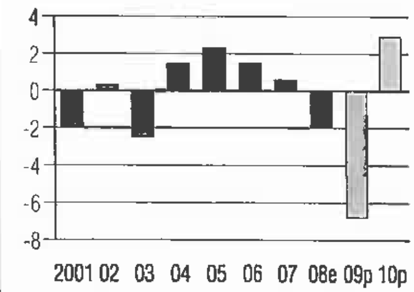
Le gouvernement provincial continuera d'investir fortement dans l'infrastructure. Les investissements publics progresseront fortement ces prochaines années, le gouvernement provincial ayant promis d'investir 37,7 milliards de dollars entre les exercices 2008 et 2013. Il a annoncé, au début de

Récession et démographie néfastes au logement
(mises en chantier de logements, unités, en 000)



p = prévisions
Sources : Le Conference Board du Canada; Base de données chronologiques sur le logement de la S.C.H.L.

Année difficile pour les exportateurs
(exportations réelles, variation en pourcentage)



e = estimations
p = prévision
Sources : Le Conference Board du Canada; Statistique Canada.

Dossier spécial

Des déficits budgétaires inévitables

La situation financière du Québec sera mise en difficulté par la récession. On s'attend à un déficit budgétaire de 3,9 milliards de dollars durant l'actuel exercice et de 3,7 milliards pour 2010–2011. Alors que le budget de 2009 ne comportait pas beaucoup de nouveaux stimulants économiques, les plans d'infrastructure annoncés précédemment donneront, quant à eux, un grand coup d'accélérateur à la province. Au total, 42 milliards de dollars ont été affectés à l'infrastructure entre 2008 et 2013. Durant l'exercice en cours, 8,3 milliards seront dépensés en projets d'investissement publics contre environ 5 milliards durant l'exercice 2008–2009. La croissance des dépenses de programmes en termes nominaux se limitera à 4,5 p. 100 en 2009–2010 et à 3,2 p. 100 en 2010–2011. On ne cessera pas d'alimenter le Fonds des générations, qui s'élèvera à 3,5 milliards d'ici au mois de mars 2011.

Les recettes totales devraient normalement baisser de 0,4 p. 100 en 2009–2010 avant de reprendre avec une modeste croissance de 2,9 p. 100 en 2010–2011. Au moment précis où le ralentissement de la croissance économique se traduisait par une baisse des recettes, le Québec a prudemment opté pour une augmentation des taxes de vente provinciales d'un point de pourcentage à partir de 2011. Il a été soucieux d'indemniser les familles à faible revenu en leur offrant de plus fortes remises sur les taxes de vente et en injectant 500 millions de dollars de plus dans le Pacte pour l'emploi sur trois ans. Dans les années à venir, le retour à un équilibre budgétaire sera le principal problème à affronter par le Québec. Avec des déficits cumulatifs qui ont toutes les chances d'atteindre 11,6 milliards les quatre prochaines années et une dette provinciale qui explose (la plus lourde de tout le Canada), le retour à des budgets équilibrés n'est pas prévu avant 2013–2014. La dette nette de la province en pourcentage du PIB devrait normalement grimper à 42,8 p. 100 cette année et jusqu'à 46,3 p. 100 d'ici à 2011! Et en 2010–2011, elle atteindra le chiffre inquiétant de 145 milliards de dollars.

cette année, qu'il relèverait les dépenses prévues de 4,1 milliards de dollars, jusqu'à un total de 41,8 milliards. Les travaux prévus comprennent le prolongement de plusieurs routes, ainsi que la construction d'installations de soins de santé. En outre, il y aura le coup d'accélérateur donné à la province par le récent budget fédéral. Les dépenses publiques réelles en capital, après de solides performances ces deux dernières années, augmenteront de 21,3 p. 100 en 2009. L'expansion se poursuivra en 2010, avec une croissance des investissements publiques en capital de 7,6 p. 100.

LE LOGEMENT SUR LA MAUVAISE PENTE

Le marché du logement régressera cette année parce que l'actuel marasme économique restreindra la demande. Disons aussi qu'il s'était développé à un rythme intenable, étant donné la composition démographique de la province. Une correction permettra donc d'aligner la construction de logements plus étroitement sur les véritables besoins démographiques. Le marché du logement québécois était encore vigoureux au début de l'année (contrairement à ce que nous avons vu dans l'Ouest du Canada). On s'attend, néanmoins, à ce que le nombre de mises en chantier de logements tombe à 37 760 unités en 2009 (soit de 21,2 p. 100) et à 34 782 unités en 2010. Les investissements résidentiels réels devraient normalement baisser de 5,4 p. 100 en 2009 malgré les incitations fédérales à la rénovation. Une chute plus importante de 9,2 p. 100 est prévue pour l'an prochain.

LES EXPORTATIONS EN FORTE BAISSE

Comme les États-Unis — le plus grand partenaire commercial du Canada — sont en pleine tempête économique, les exportations reculent. Et le pire n'est pas passé. Au Québec, on prévoit une baisse des exportations réelles de 6,8 p. 100 en 2009, la plus forte contraction du commerce depuis le début des années 1980. Ce seront des temps difficiles pour la plupart des exportateurs de la province. Les perspectives sont maussades pour les industries de l'information et de la technologie, de la foresterie, des métaux de première fusion et des pâtes et papiers. Aussi longtemps que l'industrie du logement et la consommation n'auront pas touché le fond au sud de la frontière, on ne s'attend à aucun redressement dans ces secteurs. Les États-Unis n'ayant guère de nouveaux débouchés à offrir, les fabricants de la province commencent à se tourner davantage vers les marchés émergents, qui poursuivent leur croissance. Alors qu'un peu partout dans le monde, les États multiplient les dépenses d'infrastructure publique en vue de lutter contre la récession, de nouveaux débouchés s'offrent, ces deux prochaines années, aux fournisseurs de matériaux de construction, de métaux usinés, de métaux de première fusion et de services d'ingénierie.

L'industrie de l'aérospatiale, le plus important des secteurs d'exportation, commence à ressentir les turbulences économiques mondiales. En février, la société Bombardier a fait savoir qu'elle réduirait la production de ses avions Learjet et Challenger, décision qui touchera environ 710 travailleurs permanents et contractuels de la province l'année prochaine. Elle a aussi annoncé une deuxième série de mises à pied en avril, soit 1 030 travailleurs de plus qui perdront leur emploi dans la région de Montréal. Au cours de l'exercice, elle compte livrer 25 p. 100 d'avions d'affaires de moins que l'an dernier. En même temps, elle accroîtra pourtant de 10 p. 100 ses livraisons d'avions commerciaux. Elle pourvoira 730 postes permanents à Montréal pour ses avions CSeries et Learjet 85 et son centre de finition des avions Global. Deux clients ont fait une commande ferme de 50 CSeries à 110 sièges et de jets à 130 sièges, et ils ont pris une option pour 50 de plus. Les premières livraisons sont prévues en 2013. Grâce à un substantiel accroissement des exportations à la fin de l'an dernier, on s'attend à une baisse de tout juste 0,8 p. 100 dans les exportations de produits et de pièces aérospatiaux en 2009. À l'horizon de 2010, une faible reprise de l'économie américaine, associée à la stabilisation du huard, aideront à accroître les exportations totales de 2,9 p. 100.

Scénarios conjoncturels

Court terme

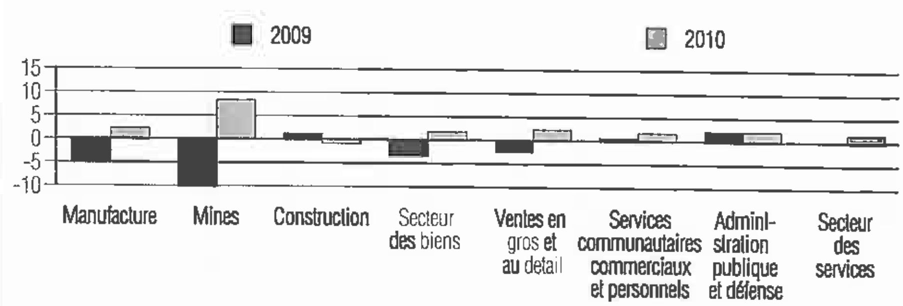
- Si l'on retarde les projets d'infrastructure publique, l'économie pourrait s'enfoncer plus profondément dans la récession.

Moyen terme

- Le retour à des déficits budgétaires pourrait limiter la contribution du gouvernement provincial à l'économie ces prochaines années.

Source : Le Conference Board du Canada.

Perspectives de l'industrie
(variation en pourcentage, $ de 2002)



Sources : Le Conference Board du Canada; Statistique Canada.

Principaux indicateurs économiques : Québec
(prévisions en date du 21 avril 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
PIB aux prix du marché (en dollars courants)	300 809	306 129	308 545	302 233	298 880	297 494	299 834	303 333	306 485	307 757	309 937	313 131	304 429	299 885	309 327
	0,2	*1,8*	*0,8*	*−2,0*	*−1,1*	*−0,5*	*0,8*	*1,2*	*1,0*	*0,4*	*0,7*	*1,0*	*2,6*	*−1,5*	*3,1*
PIB aux prix de base (en dollars courants)	282 768	287 928	290 378	284 565	281 372	280 050	282 218	285 499	288 348	289 352	291 199	294 042	286 410	282 285	290 735
	0,6	*1,8*	*0,9*	*−2,0*	*−1,1*	*−0,5*	*0,8*	*1,2*	*1,0*	*0,3*	*0,6*	*1,0*	*3,0*	*−1,4*	*3,0*
PIB aux prix de base (en dollars constants de 2002)	247 025	247 560	248 341	247 381	246 527	244 610	244 866	245 566	247 928	248 947	250 179	251 804	247 577	245 392	249 714
	0,2	*0,2*	*0,3*	*−0,4*	*−0,3*	*−0,8*	*0,1*	*0,3*	*1,0*	*0,4*	*0,5*	*0,6*	*1,0*	*−0,9*	*1,8*
Indice des prix à la consommation (2002 = 1,0)	1,114	1,134	1,139	1,124	1,121	1,130	1,137	1,145	1,153	1,159	1,167	1,175	1,127	1,133	1,163
	0,5	*1,8*	*0,4*	*−1,3*	*−0,2*	*0,8*	*0,7*	*0,7*	*0,7*	*0,6*	*0,6*	*0,7*	*2,1*	*0,5*	*2,7*
Déflateur implicite des prix — PIB aux prix de base (2002 = 1,0)	1,145	1,163	1,169	1,150	1,141	1,145	1,153	1,163	1,163	1,162	1,164	1,168	1,157	1,150	1,164
	0,4	*1,6*	*0,5*	*−1,6*	*−0,8*	*0,3*	*0,7*	*0,9*	*0,0*	*−0,1*	*0,1*	*0,3*	*2,1*	*−0,6*	*1,2*
Salaires hebdomadaires moyens (niveau)	719,4	723,9	729,2	736,4	737,1	736,5	738,9	743,2	750,2	755,0	759,9	764,8	727,2	738,9	757,5
	0,8	*0,6*	*0,7*	*1,0*	*0,1*	*−0,1*	*0,3*	*0,6*	*0,9*	*0,6*	*0,6*	*0,6*	*2,9*	*1,6*	*2,5*
Revenu des particuliers (en dollars courants)	258 450	258 535	259 558	261 353	259 449	259 281	260 575	262 630	265 431	267 571	270 268	272 462	259 474	260 483	268 933
	2,1	*0,0*	*0,4*	*0,7*	*−0,7*	*−0,1*	*0,5*	*0,8*	*1,1*	*0,8*	*1,0*	*0,8*	*3,8*	*0,4*	*3,2*
Revenu disponible des **particuliers** (en dollars courants)	197 151	198 036	199 006	200 428	198 723	198 680	199 662	201 244	202 969	204 770	206 679	208 193	198 655	199 577	205 652
	2,9	*0,4*	*0,5*	*0,7*	*−0,9*	*0,0*	*0,5*	*0,8*	*0,9*	*0,9*	*0,9*	*0,7*	*5,5*	*0,5*	*3,0*
Taux d'épargne des particuliers	2,95	2,33	1,92	3,75	3,80	3,07	2,72	2,60	2,82	3,05	3,39	2,96	2,74	3,05	3,065
Population en âge d'être active (en milliers)	6 349	6 364	6 380	6 396	6 411	6 423	6 436	6 455	6 460	6 472	6 485	6 497	6 372	6 431	6 478
	0,2	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,3*	*0,1*	*0,2*	*0,2*	*0,2*	*0,9*	*0,9*	*0,7*
Population active (en milliers)	4 183	4 186	4 180	4 192	4 178	4 167	4 182	4 200	4 216	4 226	4 238	4 249	4 185	4 182	4 232
	0,2	*0,1*	*−0,1*	*0,3*	*−0,4*	*−0,3*	*0,4*	*0,4*	*0,4*	*0,2*	*0,3*	*0,2*	*0,9*	*−0,1*	*1,2*
Emplois (en milliers)	3 888	3 877	3 869	3 889	3 845	3 811	3 799	3 799	3 803	3 810	3 819	3 833	3 881	3 813	3 816
	0,1	*−0,3*	*−0,2*	*0,5*	*−1,1*	*−0,9*	*−0,3*	*0,0*	*0,1*	*0,2*	*0,2*	*0,4*	*0,8*	*−1,7*	*0,1*
Taux de chômage	7,1	7,4	7,4	7,2	8,0	8,5	9,2	9,6	9,8	9,8	9,9	9,8	7,3	8,8	9,8
Ventes au détail (en dollars courants)	93 718	95 626	96 973	93 955	90 744	92 686	93 625	94 588	95 192	95 921	96 643	98 212	95 068	92 911	96 492
	2,1	*2,0*	*1,4*	*−3,1*	*−3,4*	*2,1*	*1,0*	*1,0*	*0,6*	*0,8*	*0,8*	*1,6*	*4,8*	*−2,3*	*3,9*
Mises en chantier (en unités)	48 096	48 195	49 212	46 101	41 503	37 360	36 190	35 988	35 674	35 695	34 739	33 020	47 901	37 760	34 782
	21,1	*0,2*	*2,1*	*−6,3*	*−10,0*	*−10,0*	*−3,1*	*−0,6*	*−0,9*	*0,1*	*−2,7*	*−4,9*	*−1,3*	*−21,2*	*−7,9*

Les données en blanc sont des prévisions.
À moins d'indications contraires, toutes les données sont exprimées en millions de dollars, au taux annuel désaisonnalisé.
Pour chaque indicateur, la première ligne donne le niveau, la deuxième la variation en pourcentage par rapport à la période précédente.
Sources: Le Conference Board du Canada; Statistique Canada; Répertoire des séries chronologiques de la Société canadienne d'hypothèques et de logement (SCHL).

Ontario

- Despite unprecedented fiscal stimulus efforts, a deteriorating trade balance and worsening labour market conditions will leave Ontario's economy in recession this year.
- Ontario's Budget 2009 stimulus commitments will add 1.2 percentage points to provincial bottom-line GDP growth in 2009.

Real GDP

	Growth	Ranking
2009	–2.4	#9
2010	2.5	#4

Credit Quality
AA
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–4.4	#8
2010	4.4	#4

Government & Background Information

Premier	Dalton McGuinty
Next election	2011
Population (2009:1)	12,986,860
Government balance (projected 2009–10)	–$14.1 million

Sources: The Conference Board of Canada; Ontario Ministry of Finance.

Ontario Economy Wallowing in Recession

by Sabrina Browarski

Prospects for the Canadian economy have deteriorated since the beginning of 2009 despite sustained (and increasingly drastic) stimulus measures undertaken by the Canadian federal government and the Bank of Canada. Ontario will absorb much of the national shock in the form of steep job losses, a contraction in real disposable incomes, anemic private investment intentions, and insipid trade outlook. Already this year, nearly half of the nation's job losses have occurred in Ontario even though the province accounts for barely more than a third of total national employment. Ontario's above-average reliance on demand from the recession-battered U.S. economy in general, and on the hard-hit auto manufacturing sector in particular, are key reasons for its poor performance.

Internally, virtually the only source of growth for the Ontario economy will be the public sector. A massive infrastructure package, combined with tax relief, was unveiled in Ontario's 2009 budget. Assuming that new spending can be implemented speedily and effectively, the new infrastructure commitments and other fiscal measures will add a sizable 1.2 per cent boost to real gross domestic product growth this year alone. By contrast, private investment intentions have dropped sharply across all categories, with total business investment slated to plunge by nearly 14 per cent in 2009. With employment prospects deteriorating and income losses rising, Ontario consumers will also scale back purchases this year.

International trade prospects arguably pose the greatest threat to a timely recovery in Ontario. With broad U.S. consumer demand weak through 2009, the province will post a trade deficit of $1.7 billion in 2009, which will balloon to $4.2 billion by 2010. In total, Ontario's real GDP at market prices will collapse by 2.4 per cent in 2009, with 2.5 per cent rebound only in 2010 as conditions stabilize south of the border.

GOVERNMENT: MASSIVE SPENDING IN VOGUE

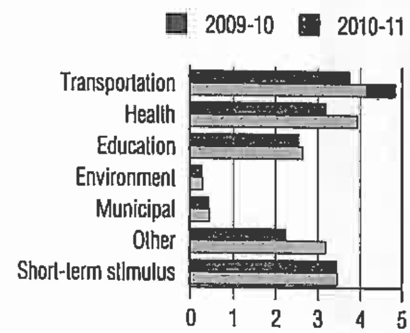
Over the last four years, the Ontario government saw revenues rise by an incredible amount. The increase allowed the government to eliminate a $5.5-billion deficit and ramp up program expenditures to the largest share of GDP in 12 years. In fact, from 2003–04 to 2007–08, average revenue growth increased by 9.2 per cent per year. By fiscal year 2007–08, revenue

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	–0.2	–2.4	2.5
Consumer Price Index	2.3	0.7	2.5
Personal disposable income	5.1	–0.2	3.8
Employment	1.4	–2.8	0.1
Unemployment rate (level)	6.5	9.2	10.3
Retail sales	3.4	–4.4	4.4
Average weekly wages	2.0	0.9	2.4
Population	1.1	1.0	1.1

Sources: The Conference Board of Canada; Statistics Canada.

Government Infrastructure Investment Plan
($ billions)



Sources: The Conference Board of Canada; Ontario Ministry of Finance.

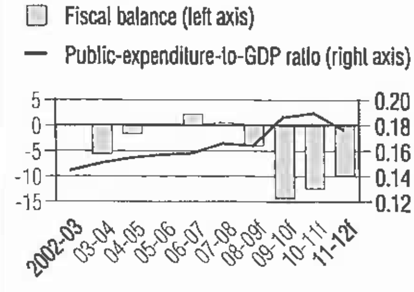
was 42 per cent higher than it had been just four years earlier. However, this trend could not continue forever, and the global financial crisis is now taking a large toll on the Ontario economy. Consistent with Conference Board estimates, the Ontario government is now expecting a substantial decline of 2.4 per cent in nominal GDP (the widest measure of the government tax base) for 2009.

It is not surprising then that for fiscal year 2008–09, provincial revenues will show a similar collapse, falling by 3.8 per cent. The sharp decline in provincial revenues, together with a large increase in program expenditures in fiscal year 2009–10, will drive Ontario further into the red than it has ever gone before. This will come at a steep cost. Net debt will rise by $56 billion over the next three years and interest payments required to service provincial debt are expected to rise by over $2 billion per year. It will take seven years and a highly ambitious expenditure control plan before the Ontario government will again be able to balance its books.

Over the medium term, the Ontario government will boost program spending in an effort to stimulate the economy. Total program expenses are forecast to rise by 12.5 per cent in fiscal year 2009–10 and by a further 5.1 per cent in 2010–11. This will cause government spending on goods and services to rise by 7.1 per cent in 2009, and a further 5 per cent next year. Budget 2009's new infrastructure stimulus plan, aimed at staving off a prolonged recessionary cycle, will come with a price tag of $27.4 billion over the next two years, a cost that will cause Ontario's fiscal deficit to soar to $14.1 billion—the largest provincial deficit in history!

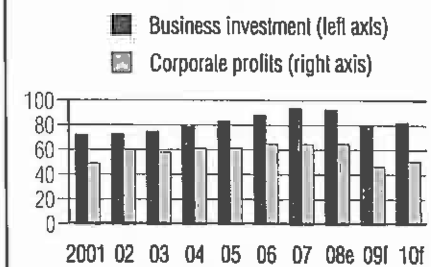
The tide will turn in 2011–12 when the Ontario government will begin its attempt to control spending in an effort to climb out of deficit. After a 2.7 per cent projected decline in program expenditures in 2012 as the stimulus package comes to an end, the Ontario government plans to limit growth in program spending to only 2.3 per cent per year until 2015–16, when it hopes to climb out of the red. There are few details of which departments will be constrained. But there is little doubt that to meet these targets, the provincial government will have to control health and education spending, which together make up two-thirds of total program expenditures. However, spending in these departments has risen at an average

Ontario Sinks Into Deepest Historical Deficit
(fiscal balance, $ billions; public-expenditure-to-GDP ratio, per cent)



f = forecast
Sources: The Conference Board of Canada; Ontario Ministry of Finance.

Profit Losses Halt Business Investment
(business investment, 2002 $ billions; pre-tax profits, $ billions)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Ontario Adopts a Harmonized Sales Tax

Ontario's 2009 budget unveiled the decision to convert the provincial retail sales tax to a harmonized value-added structure (with a few exemptions) in partnership with the federal government by July 1, 2010. Under Ontario's new value-added harmonized sales tax (HST) regime, a 13 per cent rate will be collected by the federal government (8 per cent of which will accrue to Ontario) on sales of eligible goods and services covered by the federal GST.

In the long run, harmonization with the federal base will generate myriad economic efficiency benefits for businesses and consumers.[1] Whereas the existing RST is collected only by retailers on covered goods at the point of sale to consumers, the HST will be collected at each stage of the production process. Under the HST, firms are assessed taxes on the total value of sales, but receive invoice credits for the taxes previously paid by their suppliers. As such, only the incremental value added that is generated at each stage of the supply chain will be taxed, eliminating the distortionary effects of "tax cascading," such as inflated prices on final consumer products and arbitrarily high business input costs.

Businesses will benefit from reduced compliance costs (estimated at $500 million per year) under a simplified tax administration system, which could ultimately be passed on to consumers in the form of lower prices. Ontario exports will also be free of the embedded RST, which will increase export competitiveness. Some $4 billion in offsetting relief will be provided to Ontario businesses and households to facilitate the transition to the new sales tax system and offset increased tax burdens.

1 See our *Harmonize Consumption Taxes to Improve Economic Efficiency* by Glen Hodgson and Sabrina Browarski for a detailed analysis of the mechanics of, and benefits associated with, sales tax harmonization.

annual rate of 7.2 per cent over the last four years, and previous efforts to control spending—especially in health—have failed. A key development that will assist the province in getting "back to black" is the decision to harmonize the provincial sales tax with the federal goods and services tax in 2010, a move that will generate upward of $2 billion in new revenues once fully implemented.

NO PROFITS, NO INVESTMENT

The intensification of the global financial crisis and the ensuing fallout in business confidence are causing firms to take increasingly drastic measures to ensure their economic survival. To say that business leaders are alarmed grossly understates the issue. In fact, the speed at which sentiments have eroded within the Ontario business community suggests an almost panicky reaction to progressively grimmer economic projections for 2009. The Conference Board's Index of Business Confidence currently sits 25 percentage points below the level recorded in the first quarter of 2008. Perhaps the strongest factor at play is the sharp drop anticipated for corporate profits in the coming year. Pre-tax corporate profits are expected to fall by 28 per cent relative to 2008 levels, taking nearly $18 billion out of available funds for investment purposes.

In step with recessionary sentiments, Ontario corporations have responded by significantly curtailing their capital formation expenditures. In 2009, real business investment is forecast to decline by nearly 14 per cent, with pronounced drops across all categories of investment (non-residential, machinery and equipment, and residential). With more than half of total Ontario machinery and equipment (M&E) purchased from abroad, the swift depreciation of the Canadian dollar—from parity with the U.S. dollar in the first quarter of 2008 to as low as US$0.78 in the first quarter of 2009—reversed what were previously favourable terms of trade on M&E investment. Although the federal government and several provinces have granted extensions of capital cost allowance depreciation schedules to select industries, these policies are unlikely to provide sufficient stimulus to offset the price effect of the depreciation of Canadian currency on M&E investment this year.

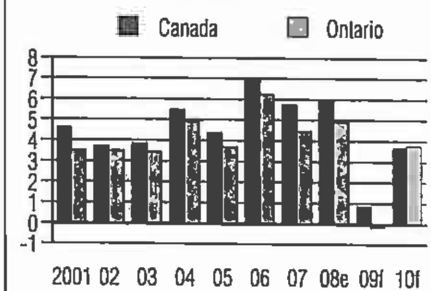
The sharp decline in provincial revenues, together with a large increase in program expenditures in fiscal year 2009–10, will drive Ontario further into the red than it has ever gone before.

A similar downward pattern is being observed in the non-residential sector. Industrial vacancy rates in Toronto are rising well above the national average, indicating that business capacity constraints are loosening quickly in Ontario. Downtown Toronto's industrial vacancy rates rose from 4.7 per cent in September 2008 to 5.5 per cent by December, owing to the completion of office construction projects and slower absorption activity. Office markets have followed a similar pattern. Non-residential construction will fall by nearly 10 per cent this year, alone.

On the residential front, tighter credit standards will contribute to a 13.5 per cent decline in real residential investment this year alongside a drop in renovations and home resales. The new federal Home Owner Tax Credit and the Home Improvement Tax Credit will contribute marginally to growth of 7.4 per cent in residential investment in 2010.

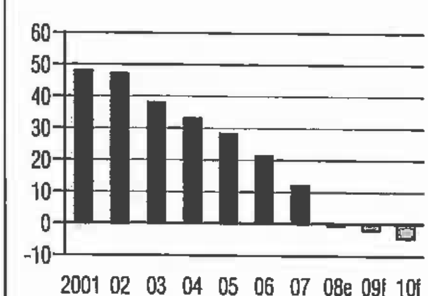
In the near term, the bulk of new investment activity will come from public funds. Real public investment activity is anticipated to rise by an astounding 27 per cent in 2009 and 20 per cent in 2010 as a result of major public spending initiatives in Ontario. Ontario's Budget 2009 unveiled a massive $27.4 stimulus package centered on infrastructure creation and renewal. Assuming that new spending can be implemented speedily and effectively, these infrastructure commitments and other fiscal measures aimed at households will add a sizable 1.2 per cent boost to real GDP growth this year alone. The multi-year MoveOntario 2020 and ReNew Ontario public infrastructure project investments—including the refurbishment of the Bruce Power CANDU reactors—will be other key generators of public investment momentum in 2009. In total, gross real capital formation will fall by 8.1 per cent in 2009, but major public spending on infrastructure will generate growth of 7 per cent in 2010.

Disposable Incomes Suffer in 2009
(percentage change)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Trade Deficits Materialize Earlier Than Expected
($ billions)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

WEALTH LOSSES HURT HOUSEHOLD SECTOR GROWTH

The Ontario job machine first began to lose steam in the final quarter of 2008; and since December 2008, the Ontario economy has shed a further 117,100 positions with all of the losses coming in full-time employment. The goods-producing sector—weighed down by trade-related losses in the manufacturing, construction, and forestry industries— has been severely affected, absorbing 58 per cent of net job losses since the beginning of the year. Going forward, the Ontario economy will continue to hemorrhage jobs well through 2009, with ultimate losses approaching 190,000 positions by year-end. Workers who remain employed will see marginal gains in real wages, although the unemployment rate will trend upward to 9.2 per cent by the end of 2009 and peak at 10.3 per cent in 2010. Province-wide, disposable incomes are forecast to retreat modestly this year as labour markets loosen, but they will recover in 2010 as employment conditions stabilize.

Ontario consumers seem unlikely to spend the economy out of recession anytime soon. Real Canadian household net worth declined by over 7 per cent at the national level in the second half of 2008 as a result of portfolio wealth losses and depreciated housing values. Manufacturing towns in southern Ontario, such as Windsor and Oshawa, have been particularly vulnerable to fluctuations in household wealth due to local plant closures, which show no imminent sign of relenting. For instance, General Motors' truck plant in Oshawa closed on May 14, leaving an estimated 2,600 workers unemployed. GM has announced that it will cut its dealership base in half by 2014, and pare total assembly employment to 4,400 by the same year. Chrysler has entered bankruptcy and will merge with Fiat SpA, a move that could threaten automotive jobs in Canada going forward. Furthermore, plant cuts in the U.S. could hurt upstream Canadian auto parts suppliers.

In export-sensitive towns, housing prices could easily experience further declines as the year unfolds. There are houses in the Windsor metropolis area selling in the $40,000 range; but as low as that is, it is still high compared with Detroit—the hub for automotive activity in the U.S.—where many houses are being listed at under $20,000.

Motor vehicle and parts manufacturers will see exports fall by nearly 40 per cent as two of the Detroit Big Three parent companies-General Motors and Chrysler-flirt with Chapter 11 bankruptcy.

Perhaps more troubling is the fact that recent Labour Force Survey data also indicate that involuntary part-time employment—a situation in which workers settle for part-time employment when they would prefer full-time work—is on the rise. In effect, this means that while the official job numbers for Ontario are grim, the situation in most job markets may, in fact, be even bleaker than the numbers suggest at first glance.

The combination of real income losses combined with recession-level consumer confidence will lead to a drop in consumer activity this year. Rising rent costs will offset purchases of broad services, while consumers will delay buying durable and semi-durable goods. However, transportation costs have trended downward in recent months, largely as a result of aggressive dealer incentives for new motor vehicles, which will encourage resurgence in consumer activity in the latter half of 2009. Furthermore, federal tax rebates for home renovations will stimulate purchases of construction materials as 2010 approaches.

POTENTIAL AUTO BANKRUPTCIES DAMAGE TRADE BALANCE

Integrative trade is particularly important for manufacturers and other exporters in Ontario, especially with regard to the trading relationship with the United States. Many parts used in the manufacturing process cross the Canada–U.S. border multiple times before a final product is finished. (Alberta—with its many pipelines carrying oil and gas to the U.S.—is the only province with a larger share of its exports destined for the United States than Ontario.) This is also why Ontario's volume of trade is so high—combined imports and exports are equivalent to 122 per cent of GDP, compared with 80 per cent for Canada as a whole.

Given the dependence of Ontario's trade sector on U.S. markets, it is hardly surprising that reduced U.S. consumer activity will generate a net trade deficit of $1.7 billion and cause Ontario's real international exports to contract by nearly 17 per cent this year. While exports of services will retreat by only a slight 2.8 per cent in 2009 as financial services output holds relatively flat, total exports of goods will fall by 19 per cent as a result of a dismal performance in the automotive sector.

Motor vehicle and parts manufacturers will see exports fall by nearly 40 per cent as two of the Detroit Big Three parent companies—General Motors and Chrysler—face the reality of Chapter 11 bankruptcy. Virtually all production lines were halted in the first quarter of 2009 in response to weak consumer demand for new motor vehicles. Looking ahead, conditions will remain challenging for the automotive sector. The Conference Board estimates that total light vehicle sales will fall below the 10 million mark in 2009, compared with sales above 16 million units in each of the previous nine years.

The head of General Motors has announced that bankruptcy is probable in the near term, although the company has been granted a June 1 deadline by the U.S. government to submit a detailed cost-cutting plan to secure additional public assistance. Further production cutbacks are expected, although no new plant or shift closures have yet been announced for Ontario plants. As well, the fate of some 9,000 automotive jobs in Ontario appears more stable thanks to the success of negotiations between Chrysler and the Canadian Auto Workers union in eliminating the $19 per hour labour cost gap between Chrysler and Japanese companies such as Toyota. A necessary precondition laid out by Industry Canada and parallel U.S. organizations for continued assistance to Chrysler was the successful negotiation of a merger between Chrysler and Fiat SpA by April 30.

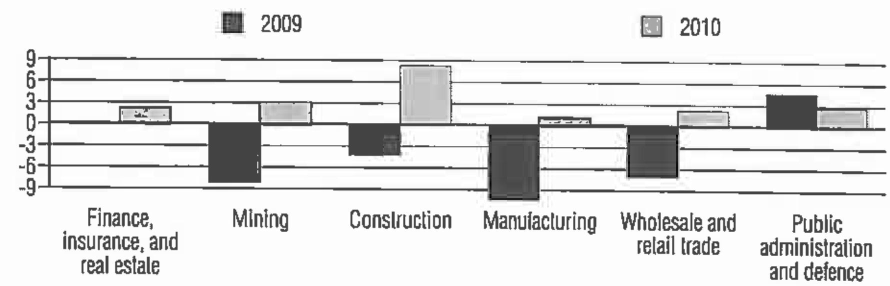
Ontario's pharmaceutical industry, which exports 40 per cent of its production to the U.S., will similarly be hurt by a recession south of the border. Although health-care spending is generally defensive, people can incur significant out-of-pocket expenses for pharmaceuticals. As a result, people can cut back on their pharmaceutical expenditures during periods of economic weakness. This is particularly true in the U.S. where there are no price controls in place, a sizable portion of the population has no health-care coverage, and job losses are mounting.

Forecast Risks

- The potential collapse of a major automotive manufacturer presents considerable downside risk to the domestic economic outlook.
- Rising public health-care costs could stimulate government spending in excess of budgetary targets.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Ontario
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	588,998	601,649	605,209	583,986	571,635	574,554	579,438	587,441	593,129	597,482	603,811	611,870	594,961	578,267	601,573
	–0.8	*2.1*	*0.6*	*–3.5*	*–2.1*	*0.5*	*0.8*	*1.4*	*1.0*	*0.7*	*1.1*	*1.3*	*1.7*	*–2.8*	*4.0*
GDP at basic prices (current $)	548,877	561,169	564,806	544,692	532,697	535,761	540,260	547,778	552,794	556,550	562,136	569,417	554,886	539,124	560,224
	–0.4	*2.2*	*0.6*	*–3.6*	*–2.2*	*0.6*	*0.8*	*1.4*	*0.9*	*0.7*	*1.0*	*1.3*	*2.1*	*–2.8*	*3.9*
GDP at basic prices (constant $ 2002)	492,508	494,055	493,974	485,560	478,545	479,487	479,640	481,168	485,565	489,342	493,548	498,175	491,524	479,710	491,657
	–1.1	*0.3*	*0.0*	*–1.7*	*–1.4*	*0.2*	*0.0*	*0.3*	*0.9*	*0.8*	*0.9*	*0.9*	*–0.3*	*–2.4*	*2.5*
Consumer Price Index (2002 = 1.0)	1.113	1.134	1.150	1.133	1.131	1.136	1.143	1.151	1.158	1.164	1.172	1.180	1.133	1.140	1.169
	0.2	*1.9*	*1.4*	*–1.4*	*–0.2*	*0.5*	*0.6*	*0.7*	*0.6*	*0.6*	*0.6*	*0.7*	*2.3*	*0.7*	*2.5*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.114	1.136	1.143	1.122	1.113	1.117	1.126	1.138	1.138	1.137	1.139	1.143	1.129	1.124	1.139
	0.6	*1.9*	*0.7*	*–1.9*	*–0.8*	*0.4*	*0.8*	*1.1*	*0.0*	*–0.1*	*0.1*	*0.4*	*2.4*	*–0.4*	*1.4*
Average weekly wages ($, industrial composite)	803.0	807.6	812.1	812.8	814.2	813.3	815.8	820.3	827.4	832.6	838.0	843.6	808.9	815.9	835.4
	0.4	*0.6*	*0.6*	*0.1*	*0.2*	*–0.1*	*0.3*	*0.6*	*0.9*	*0.6*	*0.7*	*0.7*	*2.0*	*0.9*	*2.4*
Personal income (current $)	480,639	483,812	485,250	485,072	480,781	480,100	481,838	484,727	490,077	495,968	500,748	507,517	483,693	481,861	498,577
	1.8	*0.7*	*0.3*	*0.0*	*–0.9*	*–0.1*	*0.4*	*0.6*	*1.1*	*1.2*	*1.0*	*1.4*	*4.2*	*–0.4*	*3.5*
Personal disposable income (current $)	367,875	372,631	374,503	374,066	370,444	370,376	371,809	374,083	378,440	383,840	387,662	392,888	372,269	371,678	385,707
	2.3	*1.3*	*0.5*	*–0.1*	*–1.0*	*0.0*	*0.4*	*0.6*	*1.2*	*1.4*	*1.0*	*1.3*	*4.9*	*–0.2*	*3.8*
Personal savings rate	2.99	3.30	2.62	3.89	3.79	3.06	2.70	2.57	2.81	3.32	3.40	3.74	3.20	3.03	3.32
Population of labour force age (000s)	10,449	10,488	10,531	10,571	10,604	10,651	10,696	10,723	10,752	10,791	10,831	10,872	10,510	10,669	10,811
	0.3	*0.4*	*0.4*	*0.4*	*0.3*	*0.5*	*0.4*	*0.2*	*0.3*	*0.4*	*0.4*	*0.4*	*1.4*	*1.5*	*1.3*
Labour force (000s)	7,122	7,157	7,153	7,185	7,173	7,144	7,158	7,163	7,180	7,230	7,273	7,303	7,155	7,160	7,247
	0.4	*0.5*	*–0.1*	*0.4*	*–0.2*	*–0.4*	*0.2*	*0.1*	*0.2*	*0.7*	*0.6*	*0.4*	*1.6*	*0.1*	*1.2*
Employment (000s)	6,676	6,695	6,694	6,682	6,567	6,508	6,471	6,453	6,461	6,481	6,514	6,557	6,687	6,500	6,503
	0.4	*0.3*	*0.0*	*–0.2*	*–1.7*	*–0.9*	*–0.6*	*–0.3*	*0.1*	*0.3*	*0.5*	*0.7*	*1.4*	*–2.8*	*0.1*
Unemployment rate	6.3	6.5	6.4	7.0	8.4	8.9	9.6	9.9	10.0	10.4	10.4	10.2	6.5	9.2	10.3
Retail sales (current $)	151,784	153,219	153,636	146,324	141,399	144,399	145,677	146,882	148,354	149,763	151,696	153,808	151,241	144,589	150,905
	2.2	*0.9*	*0.3*	*–4.8*	*–3.4*	*2.1*	*0.9*	*0.8*	*1.0*	*0.9*	*1.3*	*1.4*	*3.4*	*–4.4*	*4.4*
Housing starts (units)	79,670	77,353	74,718	68,562	50,294	49,327	50,165	55,704	59,935	61,770	66,555	71,259	75,076	51,372	64,880
	17.4	*–2.9*	*–3.4*	*–8.2*	*–26.6*	*–1.9*	*1.7*	*11.0*	*7.6*	*3.1*	*7.7*	*7.1*	*10.2*	*–31.6*	*26.3*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Manitoba

- The province will manage to skirt recession.
- Fuelled by job growth, solid wage gains, and $29.5 million in personal income tax cuts, consumer demand will remain healthy in 2009.

Real GDP

	Growth	Ranking
2009	1.0	#1
2010	2.4	#5

Credit Quality
AA
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–2.5	#7
2010	3.9	#6

Government & Background Information

Premier	Gary Doer
Next election	2011
Population (2009:1)	1,213,815
Government balance (estimated 2009–10)	$48 million

Sources: The Conference Board of Canada; Manitoba Finance.

Still Moving Forward Despite Negative Headwinds

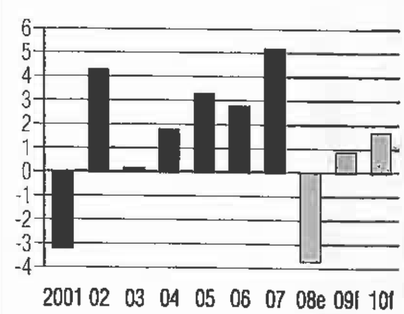
by Lin Ai, Marie-Christine Bernard

While most provinces have fallen into deficit and recession, Manitoba is expected to balance its books and post positive GDP growth. A solid outlook for construction and utilities, and decent gains in some service industries, will lift real GDP by 1 per cent in 2009. There are risks to the outlook if the Canadian and U.S. economies fail to turn around as expected and sink deeper into recession in the second half of 2009. Also, we are still waiting to assess the impacts of the worst Red River spring flooding since 1997. The status quo was assumed for spring seeding intentions and the agriculture sector. Our current forecast assumes that the increased precipitation will benefit electricity-generating capacity and utility output. With the U.S. and Canadian economies recovering, overall real GDP in Manitoba is forecast to advance by 2.4 per cent in 2010. While the province will be one of the few to show growth, not all sectors will be able to remain in positive territory. The outlook for the mining industry is bleak—particularly for metal production. In spite of fiscal incentives, spending by households will not be strong enough to prop up the economy this year. Job losses will temper consumer demand, and wholesale and retail trade output is expected to contract by 2.1 per cent in 2009. The province's manufacturing sector will remain resilient. Supported by gains in the food industry and in the production of transit and intercity buses, the manufacturing sector will face only a modest decline compared with other provinces. The province will strongly benefit from public infrastructure renewals. The strength in the construction sector will come mostly from public initiatives. In the recent budget, the provincial government raised public investment in roads, highways, wastewater treatment plants, and health and education facilities. In addition, the ongoing work on the Wuskwatim generating station will fuel private investment in the near term.

AGRICULTURE

Recent indicators suggest that seeding areas this year will shrink, affecting such staples as wheat, durum, and oats. Crop yields are forecast to decrease as well. Grain prices are not expected to rebound this year but should remain close to their five-year historical averages. Farmers will, however, benefit from the weaker Canadian dollar and from lower fuel and fertilizer costs. In general, agriculture is more resilient to business cycles. Manitoba agriculture output is forecast to grow by 1 per cent for 2009 and 1.9 per cent in 2010. The pork and beef industries are expected to fare better in 2009. Reduced North American

Mining to Rebound
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	2.5	1.0	2.4
Consumer Price Index	2.2	0.6	2.5
Personal disposable income	6.9	1.6	3.3
Employment	1.7	–0.5	0.1
Unemployment rate (level)	4.1	5.4	6.4
Retail sales	7.1	–2.5	3.9
Average weekly wages	2.5	1.6	2.6
Population	1.2	1.0	0.8

Sources: The Conference Board of Canada; Statistics Canada.

hog production (due to herd-culling programs that began in 2007 and higher feed costs that have put many producers out of businesses), along with lower feed costs and the declining value of the Canadian dollar, could restore hog prices. However, the outbreak of swine flu could delay any rebound in the hog industry. After H1N1 was discovered in a herd of pigs in Alberta, more than a dozen countries—including China—banned Canadian pork products. On a more positive note, the new trade agreement secured in principle with China this past January will expand the market for Canadian beef (particularly rib cuts and most bone-in beef products), and could boost Canadian beef exports to China by as much as $26 million.

It is uncertain how this year's severe flooding of the Red River will affect crop production. Farmers in the Red River valley grow mostly spring wheat, canola, and soybeans. While the flood will affect spring wheat seeding in Manitoba, it may prompt farmers to simply switch to soybeans, which can be planted in late spring.

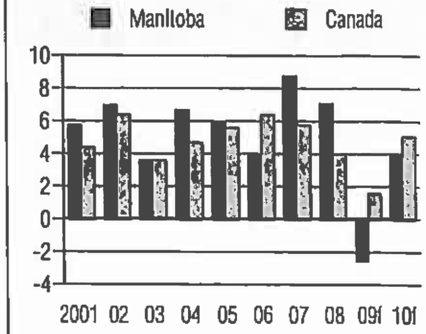
MANUFACTURING IN GOOD SHAPE

While food products remain Manitoba's largest manufacturing industry, growth over the past several years has been centred on transportation equipment manufacturing, particularly aerospace parts and buses. Despite the announced layoff of 150 workers at Boeing Winnipeg (which produces aircraft parts and components for Boeing's new 787 Dreamliner), the company has accumulated a significant backlog of orders. New Flyer Industries—a major Manitoba-based bus manufacturer that focuses on urban and heavy-duty transit vehicles, especially low-emission buses—also has a sizable quantity of backlog orders. (At the end of 2008, it had unfilled orders for 6,847 buses valued at close to $5 billion.) No major deferrals or cancellations are expected, providing relief to the 1,200 workers in the Winnipeg assembly plant. The province may also benefit from increased purchases of transit vehicles under the infrastructure plans introduced by the U.S. and Canadian governments. Overall, manufacturing output will decline by a moderate 0.9 per cent in 2009 before rising 1.7 per cent in 2010.

MINING TO REBOUND

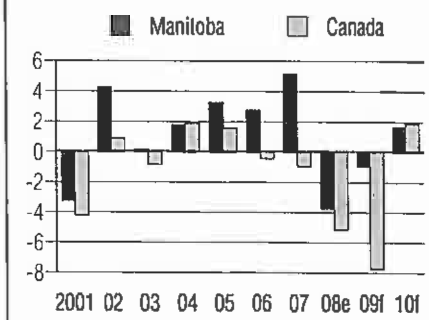
No recovery is expected for base metal demand or prices until next year. Swollen inventories will keep production of metals in check this year. Zinc-mining giant HudBay Minerals is shutting down its Chisel North

Retail Sales Suffer in 2009
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Manufacturing Fares Better
(percentage change, 2002 $)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Global Recession Does Not Derail Plans to Balance the Books

In spite of the global recession, Manitoba has tabled a budget that projects surpluses of $48 million this fiscal year and $34 million in 2010–11. Even though the province will have to draw on its rainy-day fund to the tune of $110 million in order to balance the books over the next two years, Manitoba will be one of the few provinces to remain in the black. The Manitoba budget provides plenty of stimulus to help the economy through the global downturn. The budget's main focus this year was on infrastructure spending. Last year, the province spent close to $1 billion on public infrastructure projects—this year that figure jumps to more than $1.6 billion.

Households will see their tax burden ease in the next two fiscal years thanks to commitments made in prior budgets. By opting to invest heavily in infrastructure renewal, the province had little room to relax the tax burden further. Businesses will, however, see some relief. The corporate income tax for small businesses will be cut to zero as of December 1, 2010. In addition, the general corporate income tax rate will decline from 13 per cent to 12 per cent as of this July 1. Other tax incentives were also introduced for the mining sector and for corporations that work with Manitoba research institutes on new technologies. In line with prudent fiscal planning, the province will keep program spending under control (a 2.3 per cent increase is forecast for 2009–10). Health care and education will get the lion's share of the additional money, while a third of the departments will get no increase or will see their funding lowered. Total government revenues are expected to drop by 0.4 per cent this fiscal year due to lower tax collections and a weaker economy. The Conference Board is not expecting economic growth to turn negative, providing some upside risk for revenues this year. The large increase in capital outlays will increase the province's net debt to $11.8 billion in 2009–10. Net debt as a share of nominal GDP had been steadily declining since the beginning of the decade, but that trend will be interrupted by the proposed stimulus measures.

zinc mine and concentrator in the northern Manitoban community of Snow Lake. The move by Manitoba's largest mining company will affect close to 110 jobs. Total mining output is forecast to drop 5 per cent in 2009. However, the depressed state of metal prices should only be short term in nature. Significant exploration projects for gold and base metals are planned, supported by government incentives such as tax credits, provincial exploration grants, and the Manitoba Prospectors Assistance Program. In fact, MineralFields Group, which manages and promotes tax-advantaged flow-through investments in Canada's resource sectors, is already financing numerous large projects, and it plans to finance several junior exploration ventures in the province. Overall, mining is expected to gain 5.6 per cent in 2010.

CONSTRUCTION A BRIGHT SPOT

Just as it has in the rest of the country, the housing market in Manitoba has been trending down. Housing starts retreated from an average of 5,537 units in 2008 to 3,433 units in the first quarter of this year. Although existing home sales dropped 7 per cent in the first quarter of 2009 compared with the same period last year, the decline simply means that the resale market is now more balanced after having been a seller's market for most of the past six years. New and existing home prices are still rising. For 2009, we expect the new housing market to improve through the rest of the year, leading to 4,439 new homes. In 2010, the housing market will rebound with 5,623 new units. Despite a drop in new housing construction, nominal residential investment is expected to increase by 2.6 per cent in 2009 and by 9.9 per cent in 2010, fuelled by renovation activity.

The strength in construction will come from private and public non-residential projects. Construction on the Wuskwatim dam will intensify over the forecast period; $600 million will be spent on the project in the next two years, keeping between 500 and 600 construction workers busy. In addition, Manitoba Hydro's $700-million Riel Converter Station will fuel construction activity in the near term once it gets under way, most likely within the next year. The expansion of the TransCanada Keystone pipeline will also provide construction opportunities in the province in 2010 and 2011.

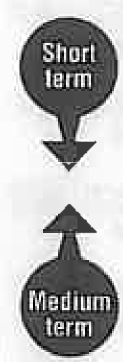
The provincial government is not staying on the sidelines. More money will be spent on infrastructure projects this year. The province is moving forward with a four-year, $4.7-billion infrastructure program to support the economy. This year alone the province intends to invest $1.6 billion in infrastructure, with $135 million coming from the federal stimulus package. All in all, total nominal non-residential investment is projected to rise by an average of 10.4 per cent in 2009–10. Construction output is forecast to rise by 5.9 per cent in 2009 and by 7.8 per cent in 2010.

LOWER INCOME GAINS BAD FOR RETAILERS

After growing strongly since 2005, labour markets slowed at the beginning of the year. The bulk of the job losses in Manitoba so far this year occurred in the agriculture and the accommodation and food services industry, as well as in the health-care and social assistance sector. While most provinces have seen full-time positions disappear, full-time employment in Manitoba was actually up 0.5 per cent in the first three months of this year. This augurs well for personal income growth. All in all, employment is forecast to decline by 0.5 per cent in 2009 and then to rebound modestly in 2010. With the real recovery in employment not beginning until 2011, the unemployment rate will rise to 5.4 per cent in this year and 6.4 per cent in 2010.

As for income prospects, with labour demand and wage growth cooling, personal income will rise by only 1.4 per cent in 2009 and by 3.4 per cent in 2010. The latest provincial budget did not provide additional personal income tax cuts. The 2007 and 2008 budgets had already announced $58 million in tax relief for 2009 and $30 million in 2010. Personal disposable income will grow by 1.6 per cent in 2009 and by 3.3 per cent in 2010. Despite fiscal incentives, retail sales are forecast to drop 2.5 per cent this year before rebounding by 3.9 per cent in 2010.

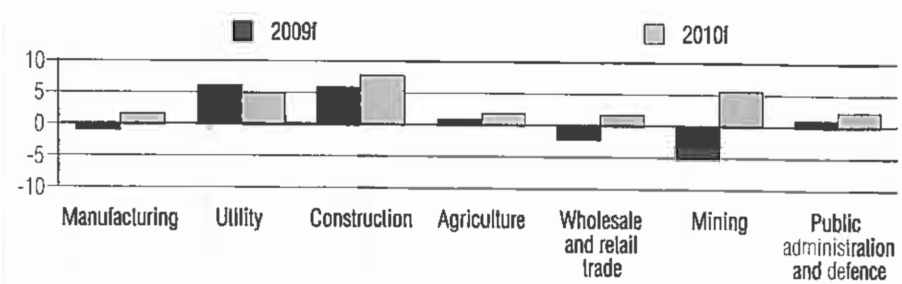
Forecast Risks



- If the infrastructure projects are delayed, economic activity will suffer.
- Major hydroelectric projects have been proposed over the next 5 to 10 years, providing strong support for the construction industry.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Manitoba
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	49,871 *−0.4*	51,233 *2.7*	51,872 *1.2*	50,036 *−3.5*	49,531 *−1.0*	49,697 *0.3*	50,259 *1.1*	51,078 *1.6*	51,575 *1.0*	51,835 *0.5*	52,292 *0.9*	52,889 *1.1*	50,753 *4.7*	50,141 *−1.2*	52,148 *4.0*
GDP at basic prices (current $)	46,520 *0.0*	47,851 *2.9*	48,497 *1.3*	46,754 *−3.6*	46,278 *−1.0*	46,457 *0.4*	46,986 *1.1*	47,765 *1.7*	48,205 *0.9*	48,415 *0.4*	48,811 *0.8*	49,342 *1.1*	47,405 *5.3*	46,871 *−1.1*	48,693 *3.9*
GDP at basic prices (constant $ 2002)	38,865 *0.3*	39,035 *0.4*	39,283 *0.6*	38,905 *−1.0*	39,219 *0.8*	39,294 *0.2*	39,436 *0.4*	39,632 *0.5*	39,941 *0.8*	40,188 *0.6*	40,473 *0.7*	40,770 *0.7*	39,022 *1.9*	39,395 *1.0*	40,343 *2.4*
Consumer Price Index (2002 = 1.0)	1.113 *0.3*	1.135 *2.0*	1.151 *1.4*	1.137 *−1.2*	1.128 *−0.8*	1.137 *0.8*	1.144 *0.6*	1.152 *0.7*	1.158 *0.6*	1.165 *0.6*	1.173 *0.7*	1.181 *0.7*	1.134 *2.2*	1.140 *0.6*	1.169 *2.5*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.197 *−0.4*	1.226 *2.4*	1.235 *0.7*	1.202 *−2.7*	1.180 *−1.8*	1.182 *0.2*	1.191 *0.8*	1.205 *1.2*	1.207 *0.1*	1.205 *−0.2*	1.206 *0.1*	1.210 *0.4*	1.215 *3.4*	1.190 *−2.1*	1.207 *1.4*
Average weekly wages (**$**, industrial composite)	704.1 *−0.2*	711.3 *1.0*	713.6 *0.3*	716.3 *0.4*	719.8 *0.5*	720.2 *0.1*	723.6 *0.5*	728.3 *0.7*	734.4 *0.8*	739.2 *0.7*	744.2 *0.7*	749.1 *0.7*	711.3 *2.5*	723.0 *1.6*	741.7 *2.6*
Personal income (current $)	40,125 *3.3*	40,254 *0.3*	40,492 *0.6*	40,670 *0.4*	40,656 *0.0*	40,775 *0.3*	41,062 *0.7*	41,382 *0.8*	41,786 *1.0*	42,116 *0.8*	42,540 *1.0*	42,929 *0.9*	40,385 *6.0*	40,969 *1.4*	42,343 *3.4*
Personal disposable income (current $)	31,696 *4.0*	31,940 *0.8*	32,182 *0.8*	32,314 *0.4*	32,286 *−0.1*	32,406 *0.4*	32,636 *0.7*	32,892 *0.8*	33,180 *0.9*	33,476 *0.9*	33,798 *1.0*	34,083 *0.8*	32,033 *7.4*	32,555 *1.6*	33,634 *3.3*
Personal savings rate	2.72	2.64	2.58	3.10	4.04	3.34	2.99	2.86	3.08	3.42	3.64	3.82	2.76	3.30	3.49
Population of labour force age (000s)	905 *0.3*	908 *0.4*	911 *0.3*	914 *0.3*	917 *0.3*	919 *0.3*	922 *0.3*	925 *0.3*	927 *0.2*	929 *0.3*	932 *0.3*	934 *0.3*	910 *1.2*	921 *1.2*	930 *1.1*
Labour force (000s)	629 *0.1*	634 *0.8*	633 *−0.1*	636 *0.4*	637 *0.2*	638 *0.2*	639 *0.2*	640 *0.2*	642 *0.3*	645 *0.3*	647 *0.3*	649 *0.3*	633 *1.4*	639 *0.9*	646 *1.1*
Employment (000s)	603 *0.1*	608 *0.9*	607 *−0.1*	608 *0.2*	606 *−0.4*	604 *−0.4*	603 *−0.1*	603 *0.0*	603 *0.0*	603 *0.1*	605 *0.2*	608 *0.5*	607 *1.7*	604 *−0.5*	605 *0.1*
Unemployment rate	4.1	4.1	4.1	4.3	4.8	5.4	5.7	5.9	6.2	6.4	6.5	6.3	4.1	5.4	6.4
Retail sales (current $)	15,035 *3.4*	15,012 *−0.2*	15,042 *0.2*	14,901 *−0.9*	14,219 *−4.6*	14,587 *2.6*	14,771 *1.3*	14,921 *1.0*	15,017 *0.6*	15,127 *0.7*	15,241 *0.8*	15,375 *0.9*	14,997 *7.1*	14,624 *−2.5*	15,190 *3.9*
Housing starts (units)	5,131 *−11.7*	5,829 *13.6*	5,222 *−10.4*	5,966 *14.3*	3,915 *−34.4*	4,122 *5.3*	4,830 *17.2*	4,888 *1.2*	5,098 *4.3*	5,449 *6.9*	5,855 *7.5*	6,091 *4.0*	5,537 *−3.5*	4,439 *−19.8*	5,623 *26.7*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Saskatchewan

- Weaker income growth will fuel a contraction in retail sales in 2009.
- The province will buck the national trend, generating 5,700 jobs.

Real GDP

	Growth	Ranking
2009	0.2	#4
2010	3.2	#1

Credit Quality

AA+
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–1.3	#5
2010	3.8	#7

Government & Background Information

Premier	Brad Wall
Next election	2011
Population (2009:1)	1,023,810
Government balance (2009–10)	$424.5 million

Sources: The Conference Board of Canada; Saskatchewan Finance.

Mining a Weak Link in the Economy

by Lin Ai and Todd A. Crawford

Global demand is drying up as the economic downturn continues to deepen. The effects on Saskatchewan have been dire, leading to a revised forecast of only 0.3 per cent growth in real gross domestic product in 2009. Goods-producing industries will suffer the most. The short-term outlook for the mining sector is negative as global demand for commodities continues to weaken, resulting in lower prices and forcing companies to curtail production. Demand for agricultural staples has also fallen, drawing down prices and curtailing the province's exports. The lone bright spot remains the construction industry, which will continue at a brisk pace as several megaprojects commence and public investment jumps. Although growth in the service industries will slow this year, the sector will escape a contraction thanks to a small expansion in the province's labour markets and to personal income tax cuts.

The province's slowdown will be short-lived as the economy bounces back next year. Labour markets will continue to expand, albeit at a slower pace, but income growth is forecast to remain above the national average, boosting domestic demand. Nominal consumer spending will expand by a healthy 3.1 per cent. The global economy should begin to emerge from recession by mid-2010, and demand for commodities and agricultural products should immediately pick up, providing a boost for the primary sector. This will also lift output in the province's manufacturing industry, as the food-processing and petroleum and coal products sectors return to normal activity levels. Builders will also be busy next year, as the housing market rebounds from a poor 2009. Combined with the enhanced infrastructure program put in place by the government, the construction industry will have an excellent year. All in all, real GDP is forecast to expand 3.2 per cent in 2010.

MINING SECTOR SUFFERS

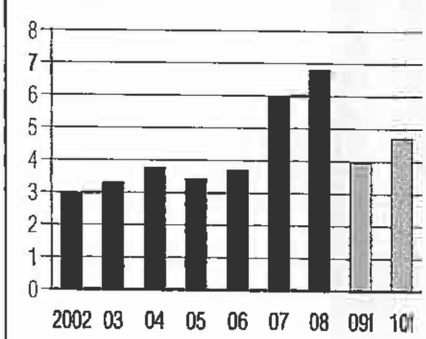
Less than 12 months ago, the energy sector in Saskatchewan was booming. Now the boom is on hold. With the benchmark West Texas Intermediate price of crude hovering around US$50 per barrel (nearly $100 below the record highs recorded last summer), drilling activity will be kept to a minimum this year. The Petroleum Services Association of Canada estimates that wells drilled in the province this year will total only 3,805—down 5 per cent from 2008. Mining services output will suffer as a result, contracting 5.2 per cent. With less drilling, oil production is predicted to be flat this year, holding output of mineral

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	4.6	0.3	3.2
Consumer Price Index	3.2	1.4	2.5
Personal disposable income	13.7	2.0	3.2
Employment	2.2	1.1	0.5
Unemployment rate (level)	4.1	5.5	6.0
Retail sales	10.3	–1.3	3.8
Average weekly wages	4.8	2.1	2.6
Population	1.6	1.3	0.8

Sources: The Conference Board of Canada; Statistics Canada.

Housing Market Peaks
(units, 000s)



f = forecast
Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

fuels to meagre growth of just 0.1 per cent. Thankfully, the energy sector slowdown is only temporary. Saskatchewan is sitting on 25 per cent of the Bakken formation's vast reserves (estimates of which range from 271 billion to 503 billion barrels). As crude prices begin to rise next year, activity will pick up throughout the forecast, and mining services will average 4 per cent annual growth over 2010 to 2013.

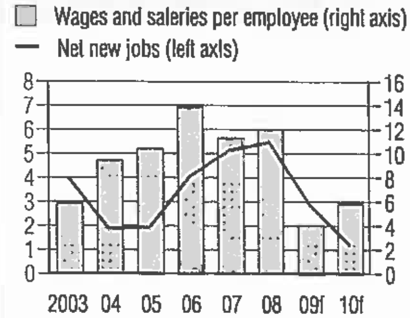
Prices for corn, wheat, and soybeans have all retreated from last year's record highs, reducing growers' incentive to boost yields and lowering demand for fertilizer. In fact, U.S. producers are on pace to reduce fertilizer use to 1982–83 levels. In an effort to counteract downward pressure on prices, PotashCorp of Saskatchewan has cut potash production by 3.5 million tonnes, resulting in 940 fewer jobs in the industry in 2009. This drop, combined with production cuts by other industry players, will lead to a drop in non-metal mining output of 17.9 per cent in 2009. Total mining will suffer as a result, falling 5.9 per cent in 2009. The downturn is expected to be temporary. Global commodity demand will stabilize as global industrial production picks back up next year. Mining output will expand 9.6 per cent in 2010, and then at an annual rate of 3.9 per cent from 2011 to 2013.

AGRICULTURE

The global recession has also hit Canada's agriculture sector. Weakening global demand for agricultural staples is resulting in reduced exports and lower prices. So far, the overall impact on agriculture has not been as severe as on the broader economy since agriculture is more resilient to business cycles. The record-high agricultural exports, prices, and farm incomes of 2007 and 2008 have left farmers on solid financial ground for now. Prices for most agricultural commodities are expected to stay relatively low compared with 2008, but they remain around their five-year averages. A modest expansion of 0.9 per cent in agricultural output is forecast for this year. Weather forecasters expect the La Niña (cooling) phenomenon to last through this year's planting season, which could lead to lower yields and put upward pressure on agricultural prices in the second half of 2009.

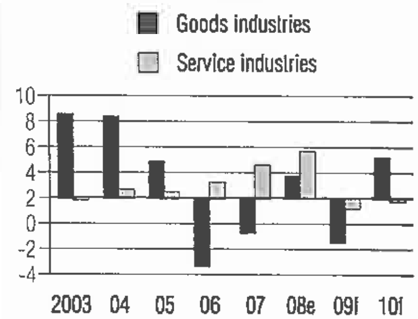
Data for the first few months of 2009 show cattle and hog export volumes and slaughtering levels down substantially from 2008. This, in turn, will likely result in lower production for 2009 and beyond, potentially providing upward pressure for cattle and hog prices. Increases in exports of Canadian beef and pork would provide

Weakening Labour Markets Slow Wage Gains
(jobs, 000s; wages, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Goods-Producing Industries Lead Economy Up and Down



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

No Deficit for Saskatchewan

The provincial government has prepared a budget that projects a 16th consecutive year of balanced books. Heavy investment in infrastructure was the main theme of last year's provincial budget, and a continued focus on infrastructure spending is included this year. The improved economic conditions of the province led to the largest personal income tax cut in the province's history last year, and a large reduction in the education portion of property taxes—which will provide an estimated $103 million in tax relief—is included in this year's budget.

The government is projecting a 4 per cent drop in nominal GDP this year (the key driver in the province's tax base), and thus revenues are forecast to fall 12.4 per cent. Non-renewable resource revenues are the main drivers behind this drop, expected to decline 27 per cent. Oil and gas prices have declined substantially from 2008 levels, lowering royalty payments, but also ensuring that Crown land sales will generate much less revenue this year. On the other hand, potash prices have not declined quite as dramatically, and potash revenues are projected to climb to $1.9 billion, up 28 per cent. If the sluggish fertilizer demand persists, potash revenues could be affected.

Total provincial expenditures will fall 1 per cent this year, allowing the government to keep its books balanced. Program spending should remain relatively flat while debt-servicing costs will fall, saving the province $26 million. The government increased its share of funding for schools by $241 million. Also, $200 million has been set aside over the next two years for a new children's hospital, with an additional $23 million to attract nurses and other health professionals in high demand. To strengthen the economic position of municipalities, $167 million has been set aside for operating grants for cities. These grants are in addition to the $100 million in infrastructure spending announced in February. Saskatchewan is in the enviable position of being able to pursue several spending initiatives while still being able to maintain a balanced budget. The government expects a surplus of $424.5 million this year.

further support for prices. New trade agreements with Asian countries will help boost exports of live animals. Moreover, lower energy and feed costs could take some of the pressure off live animal producers.

Some good news arrived in February 2009 when Saskatchewan Agriculture Minister Bob Bjornerud announced the $71-million Saskatchewan Cattle and Hog Support Program. Cattle and hog producers will be eligible for payments of $20 to $40 per head to help them cope with low market prices, high feed costs, and limited market access. This program will help producers retain their breeding herds and address immediate cash flow needs.

ANOTHER GOOD YEAR FOR CONSTRUCTION

Last year saw the housing market in the province reach a feverish pace, with 6,800 new units constructed. The boom was fuelled by strong interprovincial migration in each of the last two years. However, the housing market has likely peaked in Saskatchewan, since construction has outpaced household formation rates in recent years. Therefore, despite an influx of more than 3,000 migrants from other provinces in 2009, housing starts will fall to 3,970. The result will be a 24 per cent contraction in nominal residential investment.

On the other hand, the outlook for non-residential investment looks promising. Large projects supporting the outlook include: the $435-million Midwest uranium project by AREVA Resources, Denison Mines, and OURD Canada at McClean Lake; and Mosaic's $1.7-billion potash expansion at Esterhazy. The province will also benefit from the provincial government's enhanced infrastructure program, and energy investment will progress at a quick pace. According to Statistics Canada's *Private and Public Investment in Canada—Intentions 2009*, investment in the province's utilities sector will expand by a whopping 90 per cent. This strong non-residential investment will more than outweigh the losses from a weakening housing market, pushing output in the construction sector up 6.4 per cent this year. While growth will slow in the later years of the forecast, the overall profile remains robust as commodity prices will ensure that strong investment continues in mineral fuels, metal, and non-metal mining for years to come. Construction output will average growth of 3.5 per cent annually between 2010 and 2013.

DOMESTIC ECONOMY SLOWS

The domestic economy will slow considerably in 2009. The province will buck the national trend, actually generating 5,700 jobs in 2009. Wage growth will slow as the recession takes some of the tension out of the labour markets. Labour force growth will outpace the meagre rate of job creation, pushing the unemployment rate up to 5.5 per cent. With almost no real wage gains, personal disposable income will slow to only 2 per cent growth this year, and retailers will feel the pinch of weak income growth, as their sales contract 1.3 per cent. In fact, businesses in all industries are bracing for a rough year—corporate profits will decline 34.4 per cent. The weak housing market will drive output in finance, insurance, and real estate to only 1.2 per cent growth this year. Wholesale and retail trade will also record a poor performance, dropping 1.3 per cent. Finally, business will be cutting back on spending this year, leading to the worst performance in years by commercial services, which will see growth of only 0.8 per cent. Service-producing industries as a whole will expand 1.3 per cent—a result that would be much worse were it not for strong growth in public administration and non-commercial services.

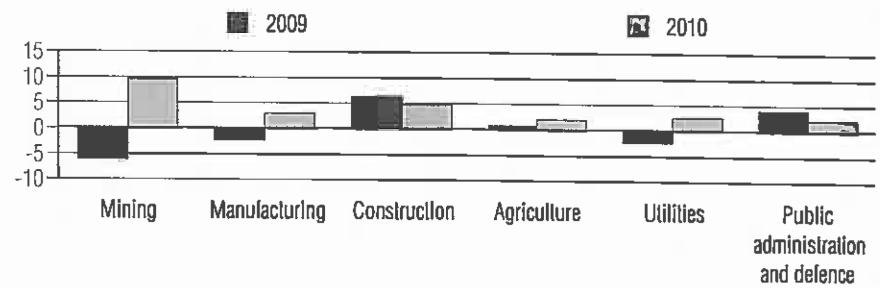
The domestic economy will remain weak through 2010, and the service industries will expand just 1.8 per cent. Employment growth will slow even further—just 2,400 net new jobs are expected – and the unemployment rate will peak at 6 per cent. Still, wage growth will pick up, spurring 3.2 per cent growth in personal disposable income. The housing market will also rebound with 4,700 new units expected. Still, the engines of growth next year will be the goods-producing industries, particularly the mining and construction sectors. Overall, output in goods-producing industries will expand 5.2 per cent—and when combined with an average performance by the service-producing industries, Saskatchewan can expect real GDP to grow 3.2 per cent next year.

Forecast Risks

- If commodity prices were to rebound sharply this year, mining industries within the province could fare better than expected.
- The province relies heavily on in-migration. As economic prospects improve around the country, fewer people may choose to move to the province, creating a labour crunch.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Saskatchewan
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	59,183	63,565	65,900	61,738	57,783	57,602	58,345	59,733	61,062	61,391	62,043	62,927	62,596	58,366	61,856
	11.1	*7.4*	*3.7*	*−6.3*	*−6.4*	*−0.3*	*1.3*	*2.4*	*2.2*	*0.5*	*1.1*	*1.4*	*21.4*	*−6.8*	*6.0*
GDP at basic prices (current $)	56,543	60,901	63,242	59,152	55,221	55,049	55,768	57,123	58,408	58,698	59,301	60,134	59,960	55,790	59,135
	12.0	*7.7*	*3.8*	*−6.5*	*−6.6*	*−0.3*	*1.3*	*2.4*	*2.2*	*0.5*	*1.0*	*1.4*	*22.8*	*−7.0*	*6.0*
GDP at basic prices (constant $ 2002)	38,890	39,566	40,311	39,638	39,531	39,556	39,722	39,993	40,503	40,816	41,140	41,433	39,601	39,700	40,973
	1.3	*1.7*	*1.9*	*−1.7*	*−0.3*	*0.1*	*0.4*	*0.7*	*1.3*	*0.8*	*0.8*	*0.7*	*5.0*	*0.2*	*3.2*
Consumer Price Index (2002 = 1.0)	1.137	1.162	1.171	1.165	1.163	1.171	1.179	1.187	1.193	1.200	1.208	1.217	1.159	1.175	1.205
	0.6	*2.2*	*0.7*	*−0.5*	*−0.2*	*0.7*	*0.6*	*0.7*	*0.6*	*0.6*	*0.7*	*0.7*	*3.2*	*1.4*	*2.5*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.454	1.539	1.569	1.492	1.397	1.392	1.404	1.428	1.442	1.438	1.441	1.451	1.514	1.405	1.443
	10.6	*5.9*	*1.9*	*−4.9*	*−6.4*	*−0.4*	*0.9*	*1.7*	*1.0*	*−0.3*	*0.2*	*0.7*	*17.0*	*−7.2*	*2.7*
Average weekly wages ($, industrial composite)	719.5	727.2	737.6	738.4	743.4	743.5	746.5	751.2	758.0	763.0	768.0	773.1	730.7	746.1	765.5
	0.8	*1.1*	*1.4*	*0.1*	*0.7*	*0.0*	*0.4*	*0.6*	*0.9*	*0.7*	*0.7*	*0.7*	*4.8*	*2.1*	*2.6*
Personal income (current $)	34,426	34,815	35,350	35,436	35,512	35,558	35,801	36,083	36,396	36,714	37,122	37,374	35,007	35,738	36,901
	5.1	*1.1*	*1.5*	*0.2*	*0.2*	*0.1*	*0.7*	*0.8*	*0.9*	*0.9*	*1.1*	*0.7*	*9.4*	*2.1*	*3.3*
Personal disposable income (current $)	27,734	28,189	28,677	28,713	28,690	28,757	28,954	29,182	29,394	29,682	30,003	30,186	28,329	28,896	29,816
	7.0	*1.6*	*1.7*	*0.1*	*−0.1*	*0.2*	*0.7*	*0.8*	*0.7*	*1.0*	*1.1*	*0.6*	*12.1*	*2.0*	*3.2*
Personal savings rate	1.34	1.28	1.82	2.69	3.05	2.18	1.83	1.70	1.92	2.27	2.50	2.68	1.79	2.19	2.34
Population of labour force age (000s)	761	765	769	773	776	778	780	782	784	785	787	788	767	779	786
	0.6	*0.6*	*0.5*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.1*	*2.1*	*1.5*	*0.9*
Labour force (000s)	530	532	536	542	546	548	549	550	552	554	555	556	535	548	554
	0.6	*0.4*	*0.8*	*1.1*	*0.8*	*0.3*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.1*	*2.1*	*2.6*	*1.1*
Employment (000s)	508	510	513	520	521	518	517	517	519	520	522	523	513	518	521
	0.7	*0.4*	*0.6*	*1.4*	*0.2*	*−0.7*	*−0.1*	*0.0*	*0.3*	*0.3*	*0.3*	*0.2*	*2.2*	*1.1*	*0.5*
Unemployment rate	4.1	4.1	4.3	4.0	4.5	5.5	5.9	6.0	6.0	6.0	6.0	6.0	4.1	5.5	6.0
Retail sales (current $)	14,166	14,401	14,537	14,191	13,728	14,106	14,277	14,421	14,490	14,613	14,748	14,840	14,324	14,133	14,673
	3.3	*1.7*	*0.9*	*−2.4*	*−3.3*	*2.8*	*1.2*	*1.0*	*0.5*	*0.8*	*0.9*	*0.6*	*10.3*	*−1.3*	*3.8*
Housing starts (units)	7,679	7,375	6,613	5,646	3,993	3,817	3,971	4,099	4,116	4,511	4,937	5,354	6,828	3,970	4,729
	35.7	*−4.0*	*−10.3*	*−14.6*	*−29.3*	*−4.4*	*4.0*	*3.2*	*0.4*	*9.6*	*9.5*	*8.4*	*13.7*	*−41.9*	*19.1*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Alberta

- Alberta will lose 24,000 jobs in 2009, temporarily reducing tensions in labour markets.
- Plummeting commodity prices have led to a massive pullback in investment.

Real GDP

	Growth	Ranking
2009	–2.4	#8
2010	2.9	#3

Credit Quality
AAA
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–4.6	#9
2010	5.2	#1

Government & Background Information

Premier	Ed Stelmach
Next election	Mar. 2012
Population (2009:1)	3,632,483
Government balance (2009–10)	–$4.7 billion

Sources: The Conference Board of Canada; Alberta Finance.

Alberta Falls Into Recession

by Todd A. Crawford

The recession has come to Alberta. Low oil prices, cancellations of projects in the oil sands, and slower consumer demand will cause the economy to contract in 2009. Output will fall severely in the goods sector. The construction industry will be particularly hard hit, contracting 14.9 per cent thanks to the massive pullback in oil- and gas-related capital expenditures. Nor will the service sector be able to escape the slowdown. The recession will lead to slower wage growth, resulting in weaker consumer demand. The service sector will gain only 0.3 per cent this year, compared with an average of 5.4 per cent over the past five years. Weak service-sector production and plummeting output in the goods-producing industries will result in the first contraction in Alberta's economy since the mid-1980s. Following a marginal 0.6 per cent gain in 2008, real gross domestic product will contract 2.4 per cent this year.

A rebound in Alberta will commence next year as the global economy begins to recover. Real GDP growth of 2.9 per cent is projected for Alberta in 2010. As credit markets loosen and global demand for mineral fuels resumes its long-term upward trend, delayed projects will get under way and construction activity will intensify. Oil prices will rise as the global economy emerges from recession in mid-2010, laying the foundation for increased non-conventional oil production and for a slight rebound in drilling activity within the province. Increased activity in oil and gas will also provide a much-needed boost to the manufacturing industry, which will grow by 2.3 per cent next year. The service sector will also begin a recovery next year, advancing 2.3 per cent as employment gains resume and wage growth intensifies.

LOW COMMODITY PRICES CAUSE INVESTMENT CRASH

Blame the global recession for Alberta's struggles this year. Industrial production has fallen precipitously around the globe, reducing demand for commodities. As a result, commodity prices have plummeted—the West Texas Intermediate benchmark price for crude oil tumbled from a high of US$147 a barrel last summer to as low as $30 in December. Natural gas prices have fared equally poorly, falling US$13 to below $4 per mmbtu.

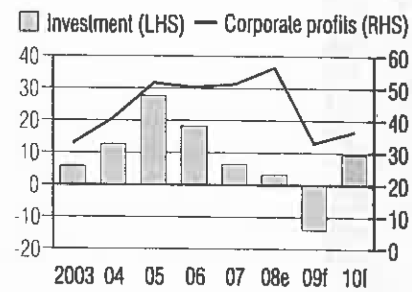
As commodity prices fell, activity in the all-important oil and gas sector ground to a halt. Corporate profits will drop 41.6 per cent this year, and most companies have slashed their investment intentions in order to cut costs. According to the Petroleum Services Association of Canada (PSAC),

Economic Indicators
(2002 $; percentage change)

	2008	2009	2010
Real GDP (basic prices)	–0.2	–2.4	2.9
Consumer Price Index	3.2	0.4	2.6
Personal disposable income	9.0	2.7	4.4
Employment	2.7	–1.2	0.6
Unemployment rate (level)	3.6	5.7	7.0
Retail sales	–0.2	–4.6	5.2
Average weekly wages	4.8	2.4	3.3
Population	2.1	2.1	1.6

Sources: The Conference Board of Canada; Statistics Canada.

Falling Profits Force Companies to Curtail Investment
($ billions)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

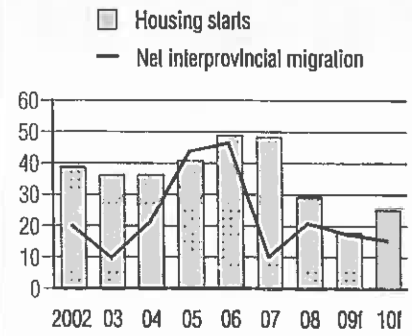
only 8,455 wells will be drilled in Alberta this year—a decline of 27 per cent from 2008. The majority of drilling is still for natural gas, and PSAC suggests that a price of at least $8 mmbtu is required to spur a significant rebound. Given current prices, there is no upside for the natural gas industry this year.

Even as natural gas activity was drying up, it was thought that megaprojects in the oil industry would carry the province through tough times. Unfortunately, it is clear that not even this booming industry will escape a slowdown. Explanations for this year's massive pullback in investment include low oil prices, high construction costs, tight credit markets, and the changes to Alberta's royalty regime. Many companies have delayed large capital investments in an effort to conserve cash. Shell Canada has withdrawn its application for its Carmon Creek project; North West Upgrading has halted its plans for a $4.2-billion upgrader; and at Petro-Canada's $25-billion Fort Hills project, mine construction has been delayed and construction on the upgrader postponed indefinitely. The situation in Alberta has gotten so bad that BA Energy has walked away from its partially completed upgrader, saying it will not consider resuming construction for at least four years.

One sector will be spared. Pipeline investment will continue unabated. According to Statistics Canada's *Private and Public Investment Intentions Survey*, investment in pipelines will expand 8 per cent this year. That compares with a 24 per cent contraction for oil and gas investment. The majority of this investment should originate in Alberta, where new pipelines are severely needed to transport future crude production. Unfortunately, pipeline investment alone will be insufficient to outweigh the crash in the oil and gas sector. Total real non-residential investment will fall 14.2 per cent this year.

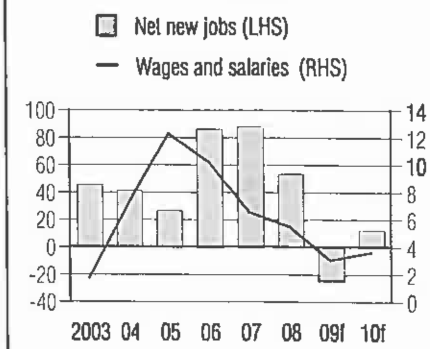
Despite a poor performance in the energy sector this year, the Conference Board estimates that activity will begin to pick back up next year. The slowdown in 2009 will help alleviate the high costs associated with materials and labour. Moreover, as the world begins to emerge from recession in mid-2010, demand for commodities should begin to rise—and that should boost activity in Alberta's oil patch to the levels seen in the past. Real non-residential investment will average annual growth of 5.9 per cent from 2010 to 2013.

Housing Markets Collapses
(000s)



f = forecast
Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

Job Losses Take Heat Off Wages
(jobs, 000s; wages, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

No More Surpluses

The government estimates the provincial deficit at $1.4 billion in fiscal 2008–09. The deficit—the first in 15 years for the province—can be traced to a net-investment loss of $1.9 billion. This year will see a more significant move into the red as revenues fall 11 per cent due to plummeting royalties and the elimination of the health-care premium (which brought in $1 billion a year). This drop will be partially offset by higher tobacco and liquor receipts, but not enough to stave off a predicted $4.7 billion deficit. The expiration of the natural gas rebate programs will push total expenditures down 1.8 per cent; however, operating expenses will still increase 3.7 per cent, mainly in health care and education. To achieve that target, however, the government will have to find savings of $215 million through value reviews of operations.

Deficits are expected until 2011–12. In order to balance its books, the government is planning to reduce expenditures by $2 billion. These cuts might not be necessary if the economy rebounds more strongly and fiscal revenues exceed expectations. The government will have to draw from the sustainability fund for at least two additional years beyond 2011–12. The sustainability fund stood at $17 billion at budget time, but will be reduced to only $3.9 billion in five years. The few tax measures included in the budget are in line with federal measures, including raising the small business income threshold to $500,000 and accelerating capital cost allowances.

Alberta remains the only province in Canada with a net-asset position, allowing the province to keep its three-year, $23.2-billion capital plan on the table. Some highlights include $5.8 billion for schools, $5.8 billion for highways, $5.3 billion for carbon capture and storage, and $5.6 billion for municipal grants. The government claims that its infrastructure program is more than double the average per-capita program spending in other provinces. This capital plan provides support for schools, roads, hospitals, and other critical infrastructure, and it provides job creation in the near term. Having racked up approximately $56 billion in surpluses over the past 15 years, Alberta can complete the program without any net borrowing over the forecast.

MINERAL FUELS PRODUCTION WEAKENS

Alberta's economy is heavily dependent on mineral fuels production, which merits special attention during these difficult times. Because so many projects have been cancelled, mineral fuels production will not advance as quickly. The drop in conventional crude and natural gas drilling are exacerbating the situation. Crude production will total 1.9 million barrels a day this year, an increase of only 2.2 per cent from last year. Natural gas production will also suffer, tumbling 6 per cent and recording a third consecutive annual decline.

Just like investment, production will bounce back starting next year. Several projects will add to production over the medium term, including Imperial Oil's Kearl Lake mine, the expansion of the Athabasca Oil Sands Project's Muskeg River, and the expansion of Canadian Natural Resources' Horizon Project. Total E&P (which bought out Synenco in 2008), Petro-Canada, North West Upgrading, Imperial Oil, and EnCana all have various projects that should begin over the forecast period. Total crude production will rise to 2.8 mmbd by 2013.

Natural gas production does not have the bright future that non-conventional oil does. Production will fall 6 per cent this year and then average annual declines of 3.1 per cent over the remaining years of the forecast. Because drilling and exploration is expected to be particularly poor for natural gas, output of mining services will fall a whopping 27 per cent this year. As natural gas prices rise starting next year, mining services are expected to rebound modestly, expanding 2.8 per cent. Robust growth, however, is projected for the outer years of the forecast as oil production really takes off and unconventional natural gas production becomes economical.

Falling natural gas production will outweigh the marginal gain expected for crude production, forcing a contraction of 1.1 per cent in mineral fuels production this year. The explosion of non-conventional crude production in coming years will ensure that mineral fuels output comes back strongly, expanding 2.9 per cent in 2010, then by an average of 6.2 per cent over 2011–13.

DOMESTIC ECONOMY WEAKENS

Labour markets have been tight in Alberta for years. Nearly 300,000 net new jobs were created over the past five years alone. Unfortunately, the province will reverse this trend in 2009, shedding 24,000 jobs as the province spirals into recession. The weaker labour market will ensure that growth in wages and salaries per employee expands only 3 per cent this year, much weaker than the 8.3 per cent rate averaged over the last five years.

Retailers will feel the pinch from weaker income growth as retail sales contract 4.6 per cent in 2009. Slower real wage growth will also influence output in community, business, and personal services, with 0.9 per cent growth expected this year. As well, fewer people (just 17,000) are expected to relocate to Alberta this year, given the weaker economy. As a result, the housing market will remain depressed for all of 2009—only 17,890 new units are expected—thus holding output in the finance, insurance, and real estate sector to only 2.1 per cent this year. Overall, service-producing industries will fare much better than goods-producing industries this year, but will still manage only 0.3 per cent growth.

Because there are so many projects in the oil sands expected to resume over the forecast, labour markets will turn around, with 12,700 net new jobs expected in 2010. Still, labour force growth will continue to outpace job creation, driving the unemployment rate up to 7 per cent—nearly double where it stood last year. As labour markets tightens, wages will expand 3.6 per cent next year, and by an average of 3.8 per cent over 2011–13. It will be a very bad year for the residential sector in 2009. Housing starts are forecast to tumble to just 17,889 units. The housing market will recover once the energy sector turns around, household formations will encourage the construction of 27,500 units on average per year from 2010 to 2013.

Forecast Risks

Short term

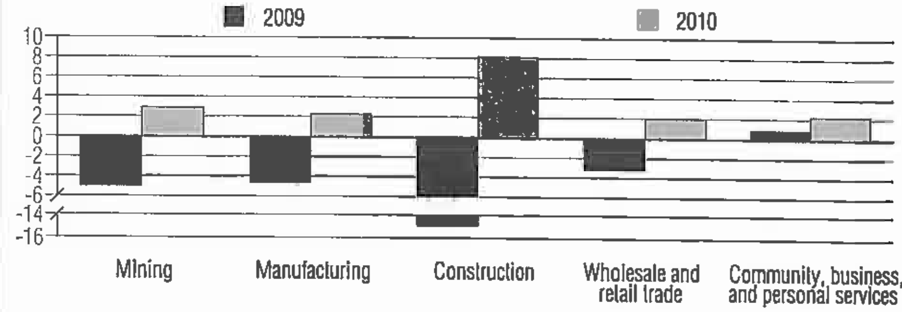
- With more favourable economic prospects in other regions, there could be fewer people relocating to Alberta, thus reducing demand for housing and other consumer goods.

Medium term

- If the global recession persists past 2010, commodity prices will remain low and delay expected investment in the oil patch.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada; Statistics Canada.

Key Economic Indicators: Alberta
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	279,127	288,478	292,494	279,026	258,206	255,017	255,873	259,774	266,515	268,855	272,693	277,882	284,781	257,217	271,486
	6.6	*3.3*	*1.4*	*-4.6*	*-7.5*	*–1.2*	*0.3*	*1.5*	*2.6*	*0.9*	*1.4*	*1.9*	*10.1*	*-9.7*	*5.5*
GDP at basic prices (current $)	269,988	279,257	283,291	270,076	249,336	246,180	246,949	250,739	257,328	259,531	263,200	268,212	275,653	248,301	262,068
	7.1	*3.4*	*1.4*	*–4.7*	*–7.7*	*–1.3*	*0.3*	*1.5*	*2.6*	*0.9*	*1.4*	*1.9*	*10.6*	*-9.9*	*5.5*
GDP at basic prices (constant $ 2002)	180,403	179,600	180,562	179,691	176,383	175,506	175,456	175,934	178,350	179,881	181,673	183,707	180,064	175,820	180,903
	1.0	*–0.4*	*0.5*	*–0.5*	*–1.8*	*–0.5*	*0.0*	*0.3*	*1.4*	*0.9*	*1.0*	*1.1*	*0.6*	*–2.4*	*2.9*
Consumer Price Index (2002 = 1.0)	1.192	1.225	1.234	1.214	1.209	1.218	1.226	1.234	1.241	1.248	1.257	1.266	1.216	1.221	1.253
	0.3	*2.8*	*0.7*	*–1.6*	*–0.5*	*0.8*	*0.6*	*0.7*	*0.6*	*0.6*	*0.7*	*0.7*	*3.2*	*0.4*	*2.6*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.497	1.555	1.569	1.503	1.414	1.403	1.407	1.425	1.443	1.443	1.449	1.460	1.531	1.412	1.449
	6.0	*3.9*	*0.9*	*–4.2*	*–5.9*	*–0.8*	*0.3*	*1.3*	*1.2*	*0.0*	*0.4*	*0.8*	*10.0*	*–7.7*	*2.6*
Average **weekly** wages ($, industrial composite)	867.3	876.8	888.0	894.9	898.7	899.1	903.3	909.6	920.0	928.0	936.0	944.2	881.7	902.7	932.1
	1.3	*1.1*	*1.3*	*0.8*	*0.4*	*0.0*	*0.5*	*0.7*	*1.1*	*0.9*	*0.9*	*0.9*	*4.8*	*2.4*	*3.3*
Personal income (current $)	168,117	170,150	172,646	174,533	174,965	174,517	175,664	177,303	179,818	182,074	184,568	187,105	171,361	175,612	183,391
	2.8	*1.2*	*1.5*	*1.1*	*0.2*	*–0.3*	*0.7*	*0.9*	*1.4*	*1.3*	*1.4*	*1.4*	*7.5*	*2.5*	*4.4*
Personal disposable income (current $)	129,792	132,248	134,492	135,811	135,994	135,809	136,702	137,971	139,728	141,718	143,570	145,442	133,086	136,619	142,615
	3.3	*1.9*	*1.7*	*1.0*	*0.1*	*–0.1*	*0.7*	*0.9*	*1.3*	*1.4*	*1.3*	*1.3*	*8.8*	*2.7*	*4.4*
Personal savings rate	13.97	15.07	15.75	17.49	18.00	17.38	17.09	16.99	17.19	17.56	17.70	17.93	15.57	17.36	17.60
Population of labour force age (000s)	2,776	2,789	2,804	2,818	2,836	2,840	2,849	2,861	2,881	2,893	2,905	2,917	2,797	2,846	2,899
	0.3	*0.5*	*0.5*	*0.5*	*0.6*	*0.1*	*0.3*	*0.4*	*0.7*	*0.4*	*0.4*	*0.4*	*2.0*	*1.8*	*1.8*
Labour force (000s)	2,070	2,082	2,090	2,109	2,115	2,100	2,107	2,117	2,132	2,147	2,159	2,173	2,088	2,110	2,153
	1.0	*0.6*	*0.4*	*0.9*	*0.3*	*–0.7*	*0.3*	*0.5*	*0.7*	*0.7*	*0.6*	*0.6*	*2.8*	*1.1*	*2.0*
Employment (000s)	1,998	2,010	2,014	2,030	2,005	1,985	1,982	1,984	1,986	1,995	2,005	2,020	2,013	1,989	2,002
	0.9	*0.6*	*0.2*	*0.8*	*–1.2*	*–1.0*	*–0.1*	*0.1*	*0.1*	*0.5*	*0.5*	*0.7*	*2.7*	*–1.2*	*0.6*
Unemployment rate	3.5	3.4	3.7	3.8	5.2	5.5	5.9	6.3	6.8	7.1	7.1	7.1	3.6	5.7	7.0
Retail sales (current $)	62,137	61,457	61,377	59,085	56,861	57,971	58,671	59,382	60,058	60,852	61,626	62,475	61,014	58,221	61,253
	0.4	*–1.1*	*–0.1*	*-3.7*	*-3.8*	*2.0*	*1.2*	*1.2*	*1.1*	*1.3*	*1.3*	*1.4*	*–0.2*	*–4.6*	*5.2*
Housing starts (units)	41,693	28,885	24,698	21,380	14,901	16,517	18,338	21,799	24,391	25,558	25,255	25,844	29,164	17,889	25,262
	–1.7	*–30.7*	*–14.5*	*–13.4*	*–30.3*	*10.8*	*11.0*	*18.9*	*11.9*	*4.8*	*–1.2*	*2.3*	*–39.7*	*–38.7*	*41.2*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

British Columbia

- The construction industry will tumble as the housing market struggles, Olympic projects are completed, and financial markets tighten.
- Employment losses will be widespread with the construction industry accounting for half the fall.

Real GDP

	Growth	Ranking
2009	–1.8	#7
2010	3.3	#1

Credit Quality
AAA
Standard & Poor's

Retail Sales

	Growth	Ranking
2009	–5.5	#10
2010	4.8	#2

Government & Background Information

Premier	Gordon Campbell
Next election	2013
Population (2009:1)	4,419,974
Government balance (estimated 2009–10)	–$495 million

Sources: The Conference Board of Canada; British Columbia Ministry of Finance.

Battered From All Sides

by Jacqueline Johnson

British Columbia's economy will be hammered this year as both its external and internal sectors are shaken. Add to that cocktail the faltering credit market, and it becomes clear that British Columbia is in a painful recession. However, next year will be much brighter for B.C. as it hosts the 2010 Olympic Games and its export sector gets a boost from the U.S. housing market's anticipated recovery. Real gross domestic product at basic prices will contract 1.8 per cent this year before posting growth of 3.3 per cent in 2010.

The forestry and manufacturing industries are facing continued plunging demand, tighter credit, and broken supply chains. This will result in continued production cuts, job losses, and mill closures, with the province's manufacturing sector losing 24,000 workers this year. However, the forestry industry is overdue for a turnaround in 2010 as the U.S. housing market stabilizes and pulp markets react to supply curtailments. Manufacturing will also begin to recover.

Low commodity prices will force metal mining production into double-digit contractions this year, and problems will persist until demand picks up again next year. On a positive note, many analysts believe that new technologies will render unconventional natural gas mining economically feasible even if prices remain low, and that will help provide stability to the ailing mining industry.

Construction will suffer this year following almost a decade of strong growth. Residential construction will drop sharply as the housing market undergoes an abrupt contraction. Meanwhile, non-residential construction will contract as Olympic projects wrap up and financing tightens. Together, real construction output will shrink 13.4 per cent in 2009.

Employment losses and low consumer confidence will pummel the domestic economy in 2009. The contraction in nominal retail sales will be deeper in B.C. than anywhere else in the country as job losses mount and average wage and salary gains slow. However, the 2010 Olympic Games will provide some much-needed commercial stimulus to an ailing domestic economy.

FORESTRY AND MANUFACTURING SQUEEZED

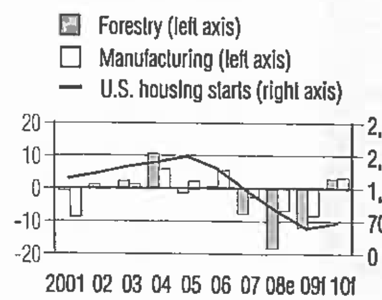
Lumber prices and demand plunged as North American housing markets contracted. Prices today are even lower than they were during the housing correction

Economic Indicators
(2002 $; percentage change)

	2008	2009f	2010f
Real GDP (basic prices)	–0.1	–1.8	3.3
Consumer Price Index	2.1	0.6	2.5
Personal disposable income	6.8	1.7	4.2
Employment	2.1	–2.6	1.0
Unemployment rate (level)	4.6	7.3	8.3
Retail sales	0.3	–5.5	4.8
Average **weekly wages**	1.5	0.9	2.6
Population	1.6	1.4	1.1

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

B.C. Forestry, Manufacturing, to Begin Recovery in 2010
(2002 $, percentage change; 000s units)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada; U.S. Commerce Department.

of the early 1990s. And with U.S. housing starts at extremely low levels and foreclosures expected to continue throughout the year, demand is suffering. However, on the supply side, the combination of low prices and North American construction industries bleeding jobs has resulted in extremely low input costs for residential housing. Furthermore, U.S. 30-year mortgage rates have fallen to an all-time low, and housing prices have continued to tumble. All these factors will bring some stability to North American housing markets in 2010. As such, a recovery in the B.C. forestry industry is anticipated in 2010, with growth of 3.1 per cent on the heels of an 11.6 per cent contraction this year.

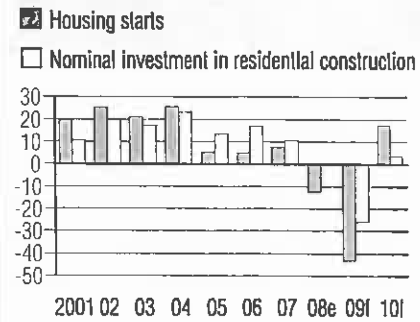
After the U.S. mortgage housing crisis began, lumber and pulp and paper mills were slow to cut production, resulting in climbing inventories. Even today, pulp production continues to outpace declining demand. This is bad news for the manufacturing sector, which will contract by 8 per cent this year. Next year, production curtailments will catch up to demand, allowing the forestry products manufacturing sector to inch its way into profitability and enabling total manufacturing to expand 3.5 per cent.

NATURAL GAS SAVES MINING

Gold and silver prices have done well during the economic downturn, as people turn to these precious metals as a store of wealth. Copper, lead, and zinc prices, however, have collapsed, bringing B.C.'s metal mining industry down with them. Real metal mining output will shrink by 16 per cent this year. China has taken advantage of the low prices to buy up mass quantities of copper (likely to fuel ambitious infrastructure plans). Despite the Chinese demand, copper prices are down almost 50 per cent on a year-over-year basis, illustrating the severity of the situation. While gold and silver prices may lose some ground next year as the economy recovers, the losses will be overshadowed by the recovery in base metal prices driven by stability in the global economy. Increased global demand will boost real metal mining output 8.9 per cent in 2010.

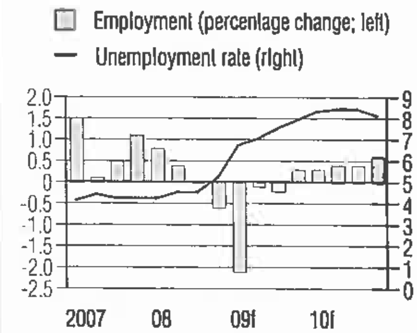
A brighter picture emerges this year in the mineral fuels sector of the industry. Unconventional natural gas mining will expand this year and next as new technologies render such mining economical, even at depressed prices. At 1.1 per cent, B.C. will be the only province anticipating growth in mineral fuels mining this year.

Housing Market Contracts
(percentage change)



e = estimate
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Labour Markets in Freefall
(percentage change; rate)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Special Issue

Olympic Torch Provides Glimmer of Light

After a less-than-stellar performance in 2008, the B.C. tourism industry is in for another hard year. The debilitating global downturn in employment and income will continue to hinder the industry's performance. Three out of every four international visitors to B.C. are American; and with the U.S. economy struggling and Americans pulling their wallets away, there will be no turnaround for the industry in 2009. Even domestic travellers are cutting back. Budget-conscious businesses and governments are reducing travel expenses, and B.C. residents are less likely to travel in the province (especially with the multitude of bargain deals popping up in other markets). As well, consumers are cutting back on restaurant meals.

To add insult to injury, many cruise liners have altered their Vancouver–Alaska cruise routes and are now sailing out of Seattle instead. The decision is logical given the current economic climate—it is simply much cheaper for Americans to buy within-U.S. flights than to fly to Vancouver. As a result, Vancouver will be hit hard. Estimates of the total losses for the Vancouver economy are in the hundreds of millions of dollars this season alone. Another ill-timed barrier to tourism will be the implementation of passport requirements for anyone—including U.S. citizens—entering the United States by land or sea. This policy will come into force on June 1 and will likely reduce travel to British Columbia.

However, there is hope on the horizon. In less than a year from now, Vancouver will host the 2010 Olympic Winter Games. Not only will hotels and restaurants in the lower mainland be full over the two weeks in February, but many tourists will be inspired to see other areas of the province, such as Victoria or the Okanagan. The Conference Board forecasts a 5.1 per cent increase in overnight visits in the province next year, with Vancouver posting a 9.3 per cent increase alone. Real output in accommodation and food services will surge 6.4 per cent in 2010, almost three times the national rate.

Perhaps even more promising is the prospect of opening up B.C. to untapped markets. Many analysts have their eyes on Mexico and Australia as prime sources for tourists to the province. The Games could prove to be the podium from which this push is launched.

CONSTRUCTION TAKES A HIKE

The construction industry will continue to suffer over the second half of 2009 due to declines in investment in both the residential and non-residential sectors. Years of strong income and employment gains, along with a demographic shift and speculation, led to an overheated residential housing market. Mounting employment losses in the province and ailing global financial markets have now forced the housing market into an abrupt correction that will last well into 2010. Housing starts will decrease 43.1 per cent this year to 19,500 units.

However, there are some stabilizers in place which will enable some groups to benefit from the correction. Most notably, houses have become more affordable. March's average MLS price was the lowest in three years. And with lumber prices at such low levels, it is difficult to imagine that the depressingly low level of housing starts seen in the first quarter of 2009 can last much longer. Already in the first three months of 2009, there was a 5.2 per cent increase in MLS sales, seasonally adjusted. Nominal investment in residential construction is forecast to decline 25.9 per cent this year before gaining 3.7 per cent in 2010.

On the non-residential side, several big ticket projects will wrap up this year. The $808-million Golden Ears Bridge across the Fraser River is expected to open this summer. The $796-million Sea-to-Sky highway improvement project will wrap up this fall, and the Canada Line rapid transit link connecting Vancouver International Airport with downtown Vancouver (the third line in Translink's Skytrain network) will open a little ahead of schedule this year at a price of $2 billion. Additionally, the Vancouver Convention Centre expansion ($883 million) and Woodward's building redevelopment ($300 million) will also be completed.

Furthermore, according to Statistics Canada's Private and Public Investment Intentions 2009 report, capital expenditures on construction (excluding housing) will be down 11.2 per cent from 2008's preliminary figures. This massive drop in construction investment will affect the entire provincial economy, which had been benefitting from increased investment for several years. However, this drop in investment likely indicates that many businesses are only postponing investment until they can have an easier time obtaining financing or until the market uncertainty eases. Once these factors start to turn around in 2010, we expect a 9.9 per cent surge in nominal non-residential construction investment.

EMPLOYMENT AND CONSUMPTION SUFFER

British Columbia saw the biggest drop in employment in Canada during the first quarter of 2009. At the same time, there was a startling shift from full-time employment to part-time employment. The goods-producing sector experienced the greatest loss, with utilities, construction, and manufacturing industries leading the way. Unfortunately, these trends are expected to continue, with losses in the construction sector accounting for more than half of the province's expected 60,000 job losses this year.

The unemployment rate topped 7.4 per cent in March, the highest rate in five years. Unemployment will continue to climb in 2010 when people re-enter the labour force in search of jobs created as the economy recovers from the recession. The unemployment rate will average 8.3 per cent in 2010—double 2007's rate.

Contractions in employment and real output will result in a difficult year for retailers. Nominal retail sales are forecast to shrink 5.5 per cent, the heftiest contraction in the country. Government spending will help to ease the burden, growing 4.9 per cent; but this level is well below the national increase. The global economic downturn will result in decreased tourism and recreational activities for the province. However, the 2010 Olympic Games will be a boon for the domestic sector. (See the Special Issue for details.) Nominal retail sales are set to grow 4.8 per cent, while real output in amusement and recreation services will expand by 10.6 per cent—the best showing among the provinces.

Forecast Risks

Short term

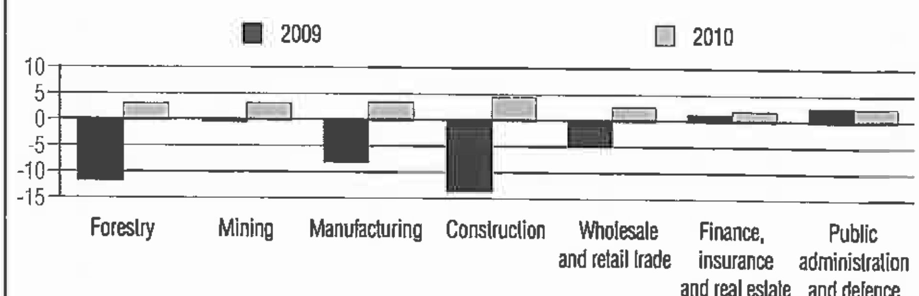
- If U.S housing starts do not begin to turn around this year, the B.C. forestry and manufacturing industries will face more severe contractions.

Medium term

- If the tightening and uncertainty in the financial markets drags on into 2010, the province will see continued investment weakness and lower medium-term potential growth.

Source: The Conference Board of Canada.

Industry Outlook
(percentage change; 2002 $)



Sources: The Conference Board of Canada.

Key Economic Indicators: British Columbia
(forecast completed Apr, 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	195,884	199,898	200,281	194,054	189,050	189,122	190,855	194,023	197,703	199,711	202,403	205,686	197,529	190,763	201,375
	−0.5	*2.0*	*0.2*	*−3.1*	*−2.6*	*0.0*	*0.9*	*1.7*	*1.9*	*1.0*	*1.3*	*1.6*	*2.5*	*−3.4*	*5.6*
GDP at basic prices (current $)	180,466	184,343	184,755	178,954	174,087	174,214	175,800	178,781	182,203	183,982	186,388	189,371	182,129	175,721	185,486
	−0.1	*2.1*	*0.2*	*−3.1*	*−2.7*	*0.1*	*0.9*	*1.7*	*1.9*	*1.0*	*1.3*	*1.6*	*3.1*	*−3.5*	*5.6*
GDP at basic prices (constant $ 2002)	152,066	152,495	152,100	150,693	148,873	148,710	149,015	149,856	152,020	153,279	154,596	155,947	151,838	149,113	153,960
	0.1	*0.3*	*−0.3*	*−0.9*	*−1.2*	*−0.1*	*0.2*	*0.6*	*1.4*	*0.8*	*0.9*	*0.9*	*0.9*	*−1.8*	*3.3*
Consumer Price Index (2002 = 1.0)	1.103	1.127	1.141	1.122	1.118	1.127	1.134	1.141	1.148	1.154	1.162	1.170	1.123	1.130	1.158
	0.2	*2.2*	*1.2*	*−1.7*	*−0.4*	*0.8*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.7*	*2.1*	*0.6*	*2.5*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.187	1.209	1.215	1.188	1.169	1.172	1.180	1.193	1.199	1.200	1.206	1.214	1.199	1.178	1.205
	−0.2	*1.9*	*0.5*	*−2.2*	*−1.5*	*0.2*	*0.7*	*1.1*	*0.5*	*0.1*	*0.4*	*0.7*	*2.1*	*−1.8*	*2.2*
Average **weekly** wages (**$**, industrial composite)	748.1	750.0	754.6	751.7	755.4	755.3	758.3	763.1	769.8	775.0	780.3	785.7	751.1	758.0	777.7
	−0.2	*0.3*	*0.6*	*−0.4*	*0.5*	*0.0*	*0.4*	*0.6*	*0.9*	*0.7*	*0.7*	*0.7*	*1.5*	*0.9*	*2.6*
Personal income (current $)	158,467	158,883	159,630	160,414	159,760	160,570	161,595	163,313	165,367	167,025	168,996	170,738	159,348	161,309	168,031
	2.2	*0.3*	*0.5*	*0.5*	*−0.4*	*0.5*	*0.6*	*1.1*	*1.3*	*1.0*	*1.2*	*1.0*	*4.9*	*1.2*	*4.2*
Personal disposable income (current $)	123,564	124,598	125,502	126,033	125,688	126,481	127,314	128,674	130,174	131,643	133,147	134,422	124,924	127,039	132,347
	2.9	*0.8*	*0.7*	*0.4*	*−0.3*	*0.6*	*0.7*	*1.1*	*1.2*	*1.1*	*1.1*	*1.0*	*6.5*	*1.7*	*4.2*
Personal savings rate	−3.17	−3.45	−3.36	−1.31	−0.79	−1.52	−1.89	−2.01	−1.69	−1.29	−1.08	−0.88	−2.82	−1.55	−1.23
Population of labour force age (000s)	3,615	3,633	3,652	3,668	3,681	3,686	3,694	3,711	3,734	3,747	3,760	3,773	3,642	3,693	3,753
	0.5	*0.5*	*0.5*	*0.4*	*0.4*	*0.1*	*0.2*	*0.5*	*0.6*	*0.4*	*0.4*	*0.4*	*2.0*	*1.4*	*1.6*
Labour force (000s)	2,412	2,429	2,431	2,432	2,420	2,424	2,432	2,450	2,467	2,478	2,488	2,496	2,426	2,431	2,482
	0.9	*0.7*	*0.1*	*0.1*	*−0.5*	*0.2*	*0.3*	*0.7*	*0.7*	*0.4*	*0.4*	*0.3*	*2.5*	*0.2*	*2.1*
Employment (000s)	2,310	2,320	2,320	2,306	2,257	2,254	2,249	2,256	2,261	2,270	2,280	2,292	2,314	2,254	2,276
	0.8	*0.4*	*0.0*	*−0.6*	*−2.1*	*−0.1*	*−0.2*	*0.3*	*0.3*	*0.4*	*0.4*	*0.6*	*2.1*	*−2.6*	*1.0*
Unemployment rate	4.2	4.5	4.5	5.2	6.7	7.0	7.5	7.9	8.3	8.4	8.4	8.1	4.6	7.3	8.3
Retail sales (current $)	57,403	57,478	57,136	53,993	51,797	53,280	53,917	54,660	55,152	55,717	56,285	56,862	56,502	53,414	56,004
	0.1	*0.1*	*−0.6*	*−5.5*	*−4.1*	*2.9*	*1.2*	*1.4*	*0.9*	*1.0*	*1.0*	*1.0*	*0.3*	*−5.5*	*4.8*
Housing starts (units)	39,176	37,863	34,955	25,290	17,708	19,077	20,546	20,751	21,374	22,336	23,341	24,568	34,321	19,521	22,905
	−7.8	*−3.4*	*−7.7*	*−27.7*	*−30.0*	*7.7*	*7.7*	*1.0*	*3.0*	*4.5*	*4.5*	*5.3*	*−12.4*	*−43.1*	*17.3*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Canada
(forecast completed Apr. 21, 2009)

	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2008:4	2009:1	2009:2	2009:3	2009:4	2008	2009	2010
GDP at market prices (current $)	1,579,180	1,619,928	1,634,256	1,576,532	1,526,360	1,524,505	1,536,598	1,559,075	1,581,150	1,592,153	1,609,291	1,631,894	1,602,474	1,536,635	1,603,622
	1.2	*2.6*	*0.9*	*–3.5*	*–3.2*	*–0.1*	*0.8*	*1.5*	*1.4*	*0.7*	*1.1*	*1.4*	*4.4*	*–4.1*	*4.4*
GDP at basic prices (current $)	1,483,388	1,523,280	1,537,792	1,482,716	1,433,393	1,431,883	1,443,058	1,464,377	1,484,847	1,494,424	1,509,789	1,530,533	1,506,794	1,443,178	1,504,899
	1.7	*2.7*	*1.0*	*–3.6*	*–3.3*	*–0.1*	*0.8*	*1.5*	*1.4*	*0.6*	*1.0*	*1.4*	*4.9*	*–4.2*	*4.3*
GDP at basic prices (constant $ 2002)	1,225,809	1,227,995	1,231,092	1,218,398	1,204,617	1,202,482	1,203,534	1,207,773	1,220,352	1,228,902	1,238,578	1,249,377	1,225,824	1,204,602	1,234,302
	–0.1	*0.2*	*0.3*	*–1.0*	*–1.1*	*–0.2*	*0.1*	*0.4*	*1.0*	*0.7*	*0.8*	*0.9*	*0.5*	*–1.7*	*2.5*
Consumer Price Index (2002 = 1.0)	1.122	1.145	1.157	1.140	1.134	1.143	1.150	1.158	1.165	1.172	1.179	1.188	1.141	1.146	1.176
	0.3	*2.0*	*1.0*	*–1.5*	*–0.5*	*0.8*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.7*	*2.4*	*0.5*	*2.6*
Implicit price deflator— **GDP at basic prices** (2002 = 1.0)	1.210	1.240	1.249	1.217	1.190	1.191	1.199	1.212	1.217	1.216	1.219	1.225	1.229	1.198	1.219
	1.8	*2.5*	*0.7*	*–2.6*	*–2.2*	*0.1*	*0.7*	*1.1*	*0.4*	*–0.1*	*0.2*	*0.5*	*4.4*	*–2.5*	*1.8*
Average weekly wages ($, industrial composite)	771.2	776.3	782.2	784.6	785.3	785.4	788.2	792.9	800.2	805.7	811.3	817.0	778.6	787.9	808.5
	0.5	*0.7*	*0.8*	*0.3*	*0.1*	*0.0*	*0.4*	*0.6*	*0.9*	*0.7*	*0.7*	*0.7*	*2.6*	*1.2*	*2.6*
Personal income (current $)	1,218,276	1,224,828	1,231,716	1,236,900	1,230,296	1,230,192	1,236,419	1,245,927	1,260,010	1,273,172	1,286,760	1,301,400	1,227,930	1,235,709	1,280,336
	2.1	*0.5*	*0.6*	*0.4*	*–0.5*	*0.0*	*0.5*	*0.8*	*1.1*	*1.0*	*1.1*	*1.1*	*4.8*	*0.6*	*3.6*
Personal disposable income (current $)	940,132	950,596	957,728	961,232	955,456	956,371	961,345	968,808	979,188	990,953	1,001,323	1,012,245	952,422	960,495	995,927
	2.7	*1.1*	*0.8*	*0.4*	*–0.6*	*0.1*	*0.5*	*0.8*	*1.1*	*1.2*	*1.0*	*1.1*	*6.0*	*0.8*	*3.7*
Personal savings rate	3.49	3.46	3.15	4.70	4.82	4.10	3.75	3.63	3.85	4.24	4.41	4.53	3.70	4.07	4.26
Population of labour force age (000s)	26,777	26,874	26,973	27,072	27,155	27,236	27,317	27,399	27,483	27,566	27,650	27,733	26,924	27,277	27,608
	0.3	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.4*	*1.3*	*1.2*
Labour force (000s)	18,167	18,244	18,246	18,323	18,304	18,256	18,305	18,360	18,431	18,524	18,607	18,675	18,245	18,306	18,559
	0.5	*0.4*	*0.0*	*0.4*	*–0.1*	*–0.3*	*0.3*	*0.3*	*0.4*	*0.5*	*0.4*	*0.4*	*1.7*	*0.3*	*1.4*
Employment (000s)	17,093	17,129	17,125	17,146	16,923	16,781	16,721	16,711	16,731	16,777	16,844	16,938	17,123	16,784	16,822
	0.5	*0.2*	*0.0*	*0.1*	*–1.3*	*–0.8*	*–0.4*	*–0.1*	*0.1*	*0.3*	*0.4*	*0.6*	*1.5*	*–2.0*	*0.2*
Unemployment rate	5.9	6.1	6.1	6.4	7.5	8.1	8.7	9.0	9.2	9.4	9.5	9.3	6.1	8.3	9.4
Retail sales (current $)	426,261	429,325	431,756	414,252	400,086	409,168	413,462	417,709	421,308	425,250	429,738	435,376	425,398	410,106	427,918
	1.7	*0.7*	*0.6*	*–4.1*	*–3.4*	*2.3*	*1.0*	*1.0*	*0.9*	*0.9*	*1.1*	*1.3*	*3.2*	*–3.6*	*4.3*
Housing starts (units)	234,974	217,390	207,389	184,471	143,389	140,203	143,502	152,413	159,036	163,604	168,914	174,494	211,056	144,877	166,512
	8.6	*–7.5*	*–4.6*	*–11.1*	*–22.3*	*–2.2*	*2.4*	*6.2*	*4.3*	*2.9*	*3.2*	*3.3*	*–7.6*	*–31.4*	*14.9*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Gross Domestic Product by Province and Industry
(forecast completed Apr. 21, 2009)

	Newfoundland and Labrador			Prince Edward Island			Nova Scotia			New Brunswick			Quebec		
	2008	2009	2010	2008	2009	2010	2008	2009	2010	2008	2009	2010	2008	2009	2010
Agriculture	52	53	54	225	231	236	227	233	240	344	350	358	3,186	3,219	3,280
	2.6	*1.9*	*1.9*	*2.7*	*2.6*	*1.9*	*1.7*	*2.6*	*2.9*	*1.7*	*1.5*	*2.4*	*0.3*	*1.0*	*1.9*
Forestry	50	40	41	7	7	7	84	75	77	249	217	223	946	890	903
	–9.9	*–20.3*	*2.2*	*–7.4*	*–10.9*	*–0.1*	*–24.2*	*–11.3*	*2.4*	*–25.5*	*–12.8*	*2.9*	*–7.4*	*–5.9*	*1.5*
Fishing & trapping	299	288	294	101	99	101	367	353	360	152	147	150	104	102	103
	7.8	*–3.5*	*1.9*	*8.2*	*–2.0*	*1.7*	*7.4*	*–4.0*	*2.2*	*7.6*	*–3.8*	*2.1*	*7.6*	*–1.8*	*0.4*
Mining	5,278	4,234	4,212	0	0	0	818	752	714	201	193	202	1,084	975	1,056
	–6.1	*–19.8*	*–0.5*	*–1.2*	*0.6*	*0.2*	*2.6*	*–8.1*	*–5.0*	*–1.7*	*–3.7*	*4.8*	*0.8*	*–10.1*	*8.4*
Manufacturing	850	740	760	430	412	425	2,864	2,718	2,780	2,609	2,529	2,601	44,819	42,568	43,581
	1.6	*–13.0*	*2.7*	*–5.1*	*–4.2*	*3.2*	*–0.7*	*–5.1*	*2.3*	*–2.8*	*–3.0*	*2.9*	*–3.4*	*–5.0*	*2.4*
Construction	665	777	778	182	172	172	1,616	1,759	1,802	1,590	1,548	1,416	14,888	15,075	14,964
	–2.0	16.8	0.2	0.9	–5.9	0.2	3.8	8.8	2.5	3.8	–2.6	–8.5	7.5	1.3	–0.7
Utilities	533	516	525	46	45	46	614	594	606	772	746	761	9,536	9,255	9,492
	–1.7	*–3.4*	*1.9*	*2.5*	*–2.7*	*2.4*	*2.6*	*–3.3*	*2.0*	*2.4*	*–3.3*	*2.0*	*–3.0*	*–2.9*	*2.6*
Goods-producing industries	7,729	6,647	6,664	993	966	987	6,592	6,484	6,580	5,916	5,730	5,712	74,564	72,084	73,381
	–4.2	*–14.0*	*0.3*	*–0.7*	*–2.7*	*2.1*	*1.2*	*–1.6*	*1.5*	*–1.2*	*–3.2*	*–0.3*	*–1.2*	*–3.3*	*1.8*
Transportation, warehousing & information & cultural industries	1,020	1,007	1,011	216	213	216	2,020	2,006	2,020	1,875	1,873	1,881	20,255	20,075	20,295
	0.0	*–1.2*	*0.4*	*1.2*	*–1.1*	*1.4*	*1.4*	*–0.7*	*0.7*	*1.2*	*–0.1*	*0.4*	*1.5*	*–0.9*	*1.1*
Wholesale & retail trade	1,543	1,573	1,599	375	379	384	3,010	3,049	3,079	2,726	2,752	2,822	29,920	29,239	29,964
	6.3	*1.9*	*1.6*	*0.0*	*1.1*	*1.3*	*1.6*	*1.3*	*1.0*	*3.3*	*1.0*	*2.5*	*2.3*	*–2.3*	*2.5*
Finance, insurance & real estate	2,200	2,216	2,242	702	703	713	5,591	5,628	5,721	3,878	3,914	3,992	42,735	42,945	43,472
	3.4	*0.7*	*1.2*	*3.0*	*0.1*	*1.4*	*1.8*	*0.7*	*1.7*	*1.9*	*0.9*	*2.0*	*2.4*	*0.5*	*1.2*
Community, business & personal services	3,646	3,734	3,811	1,023	1,020	1,038	6,861	6,923	7,034	5,070	5,211	5,511	64,023	64,500	65,691
	1.7	*2.4*	*2.1*	*2.1*	*–0.3*	*1.7*	*1.2*	*0.9*	*1.6*	*0.5*	*2.8*	*5.8*	*1.9*	*0.7*	*1.8*
Public administration & defence	1,330	1,381	1,409	487	503	513	2,845	2,915	2,963	2,121	2,199	2,235	15,790	16,138	16,500
	2.8	*3.8*	*2.1*	*3.8*	*3.3*	*2.0*	*2.1*	*2.5*	*1.7*	*4.3*	*3.6*	*1.6*	*1.8*	*2.2*	*2.2*
Service-producing industries	9,740	9,911	10,072	2,802	2,819	2,864	20,326	20,520	20,818	15,669	15,949	16,441	172,724	172,898	175,922
	2.8	*1.8*	*1.6*	*2.3*	*0.6*	*1.6*	*1.6*	*1.0*	*1.5*	*1.9*	*1.8*	*3.1*	*2.1*	*0.1*	*1.7*
All industries	17,920	17,019	17,197	3,808	3,799	3,865	26,833	26,932	27,327	21,567	21,670	22,145	247,577	245,392	249,714
	–0.5	*–5.0*	*1.0*	*1.4*	*–0.2*	*1.7*	*1.4*	*0.4*	*1.5*	*1.0*	*0.5*	*2.2*	*1.0*	*–0.9*	*1.8*

White area represents forecast data.
All data are in millions of 2002 dollars. For each industry, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada.

Gross Domestic Product by Province and Industry
(forecast completed Apr. 21, 2009)

	Ontario			Manitoba			Saskatchewan			Alberta			British Columbia		
	2008	2009	2010	2008	2009	2010	2008	2009	2010	2008	2009	2010	2008	2009	2010
Agriculture	4,570	4,627	4,722	1,813	1,831	1,866	4,286	4,324	4,415	4,576	4,637	4,716	1,207	1,218	1,236
	1.1	*1.3*	*2.1*	*5.7*	*1.0*	*1.9*	*7.7*	*0.9*	*2.1*	*0.9*	*1.3*	*1.7*	*2.2*	*1.0*	*1.4*
Forestry	482	425	444	40	35	36	3	2	2	283	259	266	2,615	2,312	2,383
	–18.8	*–11.7*	*4.4*	*–6.2*	*–12.1*	*3.6*	*–29.0*	*–32.5*	*1.9*	*–4.5*	*–8.5*	*2.8*	*–18.0*	*–11.6*	*3.1*
Fishing & trapping	49	49	49	8	8	8	0	0	0	1	1	1	130	126	127
	6.2	*0.5*	*–0.4*	*5.2*	*0.4*	*0.8*	*5.2*	*0.3*	*0.7*	*5.2*	*0.1*	*0.7*	*0.9*	*–3.5*	*0.8*
Mining	2,585	2,376	2,449	641	609	643	5,550	5,223	5,723	33,170	31,521	32,448	4,518	4,500	4,645
	0.3	*–8.1*	*3.1*	*–3.4*	*–5.0*	*5.6*	*1.3*	*–5.9*	*9.6*	*–4.8*	*–5.0*	*2.9*	*1.2*	*–0.4*	*3.2*
Manufacturing	85,247	76,432	77,358	4,771	4,726	4,805	2,847	2,787	2,874	16,815	16,035	16,401	14,519	13,352	13,826
	–7.2	*–10.3*	*1.2*	*–3.7*	*–0.9*	*1.7*	*0.2*	*–2.1*	*3.1*	*0.2*	*–4.6*	*2.3*	*–6.6*	*–8.0*	*3.5*
Construction	26,650	25,569	27,692	2,053	2,173	2,343	2,349	2,499	2,619	14,492	12,327	13,328	9,161	7,931	8,292
	2.2	*–4.1*	*8.3*	*8.9*	*5.9*	*7.8*	*9.8*	*6.4*	*4.8*	*–4.2*	*–14.9*	*8.1*	*2.1*	*–13.4*	*4.5*
Utilities	10,083	9,699	9,950	1,550	1,646	1,726	973	952	977	3,677	3,623	3,748	3,243	3,172	3,270
	1.8	*–3.8*	*2.6*	*–0.7*	*6.2*	*4.9*	*–0.3*	*–2.2*	*2.7*	*–1.1*	*–1.5*	*3.5*	*–2.0*	*–2.2*	*3.1*
Goods-producing industries	129,665	119,177	122,664	10,875	11,027	11,427	16,009	15,786	16,611	73,013	68,402	70,909	35,393	32,611	33,778
	–4.4	*–8.1*	*2.9*	*0.5*	*1.4*	*3.6*	*3.8*	*–1.4*	*5.2*	*–3.0*	*–6.3*	*3.7*	*–3.8*	*–7.9*	*3.6*
Transportation, **warehousing & information & cultural industries**	38,706	38,197	38,920	3,844	3,868	3,935	3,323	3,378	3,447	14,829	14,624	14,954	15,205	14,836	15,223
	1.0	*–1.3*	*1.9*	*–0.3*	*0.6*	*1.7*	*2.6*	*1.7*	*2.0*	*0.3*	*–1.4*	*2.3*	*–0.4*	*–2.4*	*2.6*
Wholesale & retail trade	58,544	54,468	55,711	5,096	4,991	5,080	5,323	5,254	5,336	20,058	19,410	19,804	17,972	17,098	17,553
	–0.4	*–7.0*	*2.3*	*4.1*	*–2.1*	*1.8*	*16.2*	*–1.3*	*1.5*	*3.4*	*–3.2*	*2.0*	*0.1*	*–4.9*	*2.7*
Finance, insurance & real estate	112,017	112,040	114,590	7,321	7,453	7,578	6,030	6,101	6,207	29,776	30,410	31,173	35,984	36,460	37,205
	1.4	*0.0*	*2.3*	*4.2*	*1.8*	*1.7*	*5.2*	*1.2*	*1.7*	*5.4*	*2.1*	*2.5*	*4.5*	*1.3*	*2.0*
Community, business & personal services	124,370	126,137	129,297	9,207	9,328	9,534	7,592	7,754	7,899	38,655	38,997	39,875	39,692	40,235	42,118
	1.9	*1.4*	*2.5*	*1.9*	*1.3*	*2.2*	*2.1*	*2.1*	*1.9*	*2.6*	*0.9*	*2.2*	*3.1*	*1.4*	*4.7*
Public administration & defence	26,323	27,550	28,334	2,668	2,697	2,760	1,962	2,045	2,092	6,850	7,005	7,219	7,810	8,018	8,227
	3.7	*4.7*	*2.8*	*1.5*	*1.1*	*2.3*	*2.1*	*4.2*	*2.3*	*3.7*	*2.3*	*3.1*	*3.3*	*2.7*	*2.6*
Service-producing industries	359,961	358,392	366,853	28,136	28,337	28,886	24,230	24,532	24,980	110,168	110,447	113,024	116,663	116,646	120,326
	1.4	*–0.4*	*2.4*	*2.6*	*0.7*	*1.9*	*5.8*	*1.2*	*1.8*	*3.2*	*0.3*	*2.3*	*2.6*	*0.0*	*3.2*
All industries	491,524	479,710	491,657	39,022	39,395	40,343	39,601	39,700	40,973	180,064	175,820	180,903	151,838	149,113	153,960
	–0.3	*–2.4*	*2.5*	*1.9*	*1.0*	*2.4*	*5.0*	*0.2*	*3.2*	*0.6*	*–2.4*	*2.9*	*0.9*	*–1.8*	*3.3*

White area represents forecast data.
All data are in millions of 2002 dollars. For each industry, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada.

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Cost of Service Study

May 2009

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1.0 GENERAL

Cost of service studies are conducted on a regular basis to evaluate the reasonableness of cost recovery by class of service and as a step in the traditional process for establishing the Company's rates.

At the Company's 2003 General Rate proceeding, the Company presented detailed evidence on its cost of service study methodology. Through a mediation process, the parties at the hearing recommended the approval of the cost of service study methodology.

In Board Order No. P.U. 19 (2003) the Board approved the recommendations as presented in the evidence and the Mediation Report.

In Board Order No. P.U. 32 (2007) the Board stated that is was satisfied that Newfoundland Power's ("NP's") COS Study and methodology, along with the Marginal Cost Study, are appropriate to be used in establishing 2008 customer rates.

2.0 2008 COST OF SERVICE STUDY

The Company has completed a 2008 Cost of Service Study (the "Cost of Service Study"). The detailed results of the Cost of Service Study are shown in Appendix A. The Cost of Service Study reflects actual costs and revenue incurred in 2008.

2.1 Cost of Service Study Updates

The Cost of Service Study incorporates results from four specific studies which are updated every five years. These studies have been updated based on 2006 actual costs and the results are included in the 2008 Cost of Service Study. The four studies are:

- Customer Weighting Factor Study;
- Minimum System Analysis;
- Transformer Zero Intercept Analysis; and
- General Plant Allocation Study.

In aggregate, the updates to the four studies had the following impact on the Company's revenue to cost ratios.

Table 1
Revenue to Cost Ratios
(Percentage)

	With Old Studies	**With New Studies**	**Variance**
Domestic	94.4	94.3	(0.1)
General Service			
(0-10kW)	115.4	115.8	0.4
(10-100kW)	114.5	114.9	0.4
(110-1000kVA)	109.5	110.3	0.8
(1000kVA and Over)	104.1	104.4	0.3
Street Lighting	105.3	103.2	(2.1)
Total	**100.0**	**100.0**	**0.0**

In addition, the Company updated the Cost of Service Study primarily to recognize changes in accounting practices. The updates are:

i) The Company adopted the Asset Rate Base Method ("ARBM") for calculating rate base in 2008, as approved in Order No. P.U. 32 (2007). The 2008 Cost of Service Study reflects the adjustments made to the calculation of rate base to reflect the adoption of the ARBM.

ii) Other revenue for 2008 includes adjustments, transfers and all items under other revenue as reported in Return 14 of the Company's 2008 Annual Return to the Board.

iii) The Cost of Service Study has allocated the return and taxes related to the Municipal Tax liability and the 2005 unbilled revenue liability to each customer class based on revenue. This is consistent with the cost of service treatment for other revenue related items (e.g. Board Assessments).

iv) The purchased power expense for 2008 now includes four additional items. These items are; the amortization of replacement energy costs for Rattling Brook, the amortization of the 2006 Purchase Power Unit Cost Variance Reserve balance, the amortization of the Degree Day Component of the Weather Normalization Reserve Account and the 2008 transfer from the Demand Management Incentive ("DMI") Account. All purchased power expenses are classified between demand and energy.

3.0 COST OF SERVICE STUDY RESULTS

Appendix A shows the detailed Cost of Service Study. The following is a description of the schedules provided in Appendix A.

The results of the Cost of Service Study have been divided into five groups of schedules.

Group 1 - Results
Group 2 - Functional Classification of Rate Base
Group 3 - Functional Classification of Expenses
Group 4 - Determination of Class Allocation Factors
Group 5 - Miscellaneous Schedules

3.1 Group 1: Results

Schedule 1.1 shows the major components that make up the total cost of service (excluding Rate Stabilization Costs, Municipal Taxes and the rural deficit funding). These include purchased power expenses[1], operating and maintenance expenses, depreciation expenses, expense credits and return and taxes. The schedule shows the breakdown of these cost components into the various functional classification groups used in the study. Expense credits include revenue that is not generated from rates and is associated with particular functional classification groups.

Schedule 1.2 provides the cost by each functional classification group and the amount allocated to each class of service. The costs do not include Rate Stabilization Costs, Municipal Taxes or the rural deficit funding.

Schedule 1.3 shows the total cost of service by class of service including Rate Stabilization Costs, Municipal Taxes and the rural deficit funding. The schedule also subtracts other revenue from total costs to provide a column representing the total costs recovered from customer final rates.

Schedule 1.4 shows the revenue attributed to each class of service. This schedule shows all the components that make up the total billings to customer plus other revenue. The other revenue amount excludes the revenue treated as expense credits in Schedule 1.1. Other revenue is attributed to each class of service based on the total revenue from base rates by class.

Schedule 1.5 compares the revenue by class to the cost by class and shows the revenue to cost ratios for each class of service. The costs from Schedule 1.3 and the revenues from Schedule 1.4 are used to compute the revenue to cost ratios.

Schedule 1.6 provides rate loaders that when applied to the classified cost components (demand, energy, customer and specifically assigned costs) result in costs that can be compared to final customer rate components. The rate loaders are applied to each of the classified cost components. The RSA loader is added to the classified energy costs.

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[1] The purchased power expense excludes the portion of the expense that is attributed to funding Hydro's rural deficit.

Schedule 1.7 expresses the cost of service in terms of unit costs. The units costs provided are the $ per kW/kVA for demand costs, ¢/kWh for energy costs, and $/bill for customer related costs. Also provided is a breakdown of demand and customer cost in ¢/kWh and an overall total cost expressed in terms of ¢/kWh.

3.2 Group 2: Functional Classification of Rate Base

Schedule 2.1 shows the original cost of the Company's fixed assets and its breakdown by the various functional classification categories. The total cost is based on the average amount of fixed assets employed during the year.

Schedule 2.2 shows the average accumulated depreciation and its breakdown into functional classification categories.

Schedule 2.3 shows the net contributions in aid of construction ("CIAC"). The net CIAC is the total CIAC received from customers and governments less the CIAC amortized to date.

Schedule 2.4 shows the average rate base. The average rate base includes the total net utility plant, deductions from rate base and additions to rate base.[2] The net utility plant is the original cost of the fixed assets (Schedule 2.1) less the accumulated depreciation (Schedule 2.2).

3.3 Group 3: Functional Classification of Expenses

Schedule 3.1 provides a summary of the Company's expenses, both regulated and non-regulated, by cost of service expense category.

Schedule 3.2 shows the functional classification of the Company's expenses by expense category as follows:

1. Purchased Power Expense. The expense shown in the schedule excludes the portion of the purchase power cost associated with funding Hydro's rural deficit.

2. Direct Operating and Maintenance Expenses. These expenses include those internal costs that can be directly placed into functional groups.

3. General System Expense. These expenses include costs related to general operations, communications and the system control center.

[2] The deductions from average rate base include the net CIAC (Schedule 2.3), Municipal tax liability, unrecognized 2005 unbilled revenue, customer security deposits, accrued pension obligation, future income taxes, demand management incentive account and the purchased power unit cost variance reserve. The additions to rate base include deferred charges (mostly pension costs), deferred energy replacement costs, unamortized regulatory cost deferral, customer finance programs, cash working capital allowance, materials and supplies allowances and the weather normalization reserve. Since the balance in the weather normalization reserve is owed from customers, the balance is added to rate base.

4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance, conservation and demand management, and regulatory costs.

Schedule 3.3 shows the breakdown of depreciation expense, net of CIAC amortization, into functional classification categories.

3.4 Group 4: Determination of Class Allocation Factors

Schedule 4.1 provides the customer statistics used to develop the allocation factors. The statistics include: the number of customers; total energy sales; total billing demand (where applicable); the estimated class load factors based on non-coincident peak ("NCP"); and the estimated class load factors based on coincident peak ("1 CP"). Schedule 4.1 also provides the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1 CP).

Schedule 4.2 provides the loss factors that are used as an input in calculating the energy and demand allocation factors.

Schedule 4.3 provides the development of the allocation factors for customer related costs. The allocation factor for each type of customer cost is based on a weighting factor and the number of customers. It should be noted that an allocation factor of 0.0 per cent occurs in a number of instances, such as the allocation factor used to allocate customer related secondary costs to transmission customers. This reflects the concept that a transmission customer (a customer that takes their electricity supply from the transmission system) is not responsible for any of the cost of the distribution secondary or distribution primary system.

Schedule 4.4 shows the development of the secondary, primary and transmission allocation factors for energy related costs. The allocation factors are based on energy sales and losses. Three separate allocation factors are required to ensure that within the cost of service study, a transmission customer is not allocated any of the cost of the distribution secondary or primary system and that a distribution primary customer is not allocated any of the cost of the distribution secondary system.

Schedule 4.5 shows the development of the NCP demand allocation factors. The allocation factors are based on the estimated class peak and the loss factors shown in Schedule 4.1 and Schedule 4.2 respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

Schedule 4.6 shows the development of the 1 CP demand allocation factor. The allocation factors are based on the estimated class demand at time of system peak and the loss factors shown in Schedule 4.1 and Schedule 4.2, respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

3.5 Group 5: Miscellaneous Schedules

Schedule 5.1 shows the functional classification splits used in the Cost of Service Study. The input data was primarily derived from a variety of functionalization and classification studies. The sources of each functionalization and classification split are detailed in the footnotes in Schedule 5.1.

Schedule 5.2 provides a reconciliation of the total expenses used in the Cost of Service Study to the 2008 Annual Report to the Board.

Schedule 5.3 provides a reconciliation of the total revenue used in the Cost of Service Study to the 2008 Annual Report to the Board.

Schedule 5.4 provides a reconciliation of the total return and taxes used in the Cost of Service Study to the 2008 Annual Report to the Board.

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Notes:

1 - Within the Schedules rows and columns may not add due to rounding.

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FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE (Excluding RSA, MTA and Rural Subsidy)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Customer Acc. & Cust. Serv.	Customer Specific	Revenue Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Purchase Power	300,333	107,841	192,492	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating and Maintenance	52,801	3,770	3,185	4,752	4,067	6,446	3,626	1,583	586	1,611	906	4,075	1,190	2,302	14,796	44	(138)
3	Depreciation	40,649	3,264	2,374	5,028	2,600	8,376	4,712	2,368	876	2,094	1,178	1,839	919	2,236	2,738	48	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	456	0	0	456	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	159	0	0	0	0	102	57	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	8,861	0	0	0	0	4,537	2,552	0	0	1,134	638	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	84	0	0	0	0	0	0	0	0	0	0	84	0	0	0	0	0
8	Customer Service Fees	306	0	0	0	0	0	0	0	0	0	0	0	0	0	306	0	0
	RSA Transfer - Energy Supply Cost Variance																	
9	Total Expense Credits	9,866	0	0	456	0	4,638	2,609	0	0	1,134	638	84	0	0	306	0	0
10	Subtotal Expenses	383,917	114,876	198,051	9,324	6,667	10,184	5,728	3,951	1,461	2,571	1,446	5,830	2,109	4,538	17,228	91	(138)
11	Return and Taxes	87,044	7,609	7,749	10,006	6,988	18,520	10,311	6,072	2,223	4,630	2,578	3,180	1,724	2,907	4,171	99	(1,723)
12	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	470,961	122,485	205,800	19,329	13,655	28,704	16,039	10,024	3,685	7,201	4,024	9,010	3,833	7,445	21,399	191	(1,862)

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FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE (Excluding RSA, MTA and Rural Subsidy)

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 4. (Excludes the Rural Deficit of $36,325,023.)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 31 less Line 4. (Excludes non-regulated expenses of $1,496,555.)
3	Depreciation	Taken from Schedule 3.3, Line 20
	Expense Credits	
	Wheeling Revenues	
4	Transmission	Allocated based on functional classification of Transmission O&M expenses excluding specifically assigned (Schedule 3.2, Line 7).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 12, Columns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 12).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 13).
8	Customer Service Fees	Functional Classification based on 100% Customer Service/ Customer Accounting.
9	Total Expense Credits	Sum of lines 4 through 8.
10	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 9. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
11	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 41. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
12	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	Total of Lines 10 and 11.

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE (Excluding RSA, MTA and Rural Deficit)
Total Cost of Service excludes RSA, MTA and Rural Deficit (All numbers are times $1,000)

Line No.	Class of Service	Rate Code	Total	Produced & Purchased Demand A	Produced & Purchased Energy B	Transmission Demand C	Distribution: Substation Demand D	Distribution: Primary Demand E	Distribution: Primary Customer F	Distribution: Transformers Demand G	Distribution: Transformers Customer H	Distribution: Secondary Demand I	Distribution: Secondary Customer J	Distribution: Services Customer K	Distribution: Meters Customer L	Distribution: St. Lighting Customer M	Customer Acc. & Cust. Serv. N	Specifically Assigned O	Revenue Related P
	Allocation Factors Used ==>			Transmission 1CP	Transmission Energy	Transmission 1CP	Primary NCP	Primary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Weighted Customers	Weighted Customers		Weighted Customers		Revenue
	DOMESTIC																		
1	Domestic Regular	1.1	84,831	19,639	31,753	3,099	2,460	5,170	5,605	1,938	1,229	1,392	1,407	3,274	825	0	7,352	0	(312)
2	Domestic All Electric	1.1	221,890	63,042	92,090	9,949	6,404	13,461	8,283	5,045	1,817	3,624	2,079	4,839	1,219	0	10,865	0	(826)
3	Total Domestic	1.1	306,721	82,681	123,844	13,048	8,863	18,631	13,887	6,982	3,046	5,016	3,486	8,114	2,043	0	18,218	0	(1,138)
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	9,614	1,726	3,513	272	230	483	814	181	214	130	204	475	239	0	1,174	0	(44)
5	(10-100 kW)	2.2	51,930	13,626	25,391	2,150	1,608	3,380	587	1,267	232	910	147	377	950	0	1,541	0	(237)
	(110-1000 kVA)	2.3																	
6	Primary (110-350 kVA)		1,465	383	823	61	48	101	2	0	0	0	0	0	48	0	5	0	(7)
7	Secondary (110-350 kVA)		30,235	7,735	16,515	1,221	970	2,039	53	764	35	549	13	43	297	0	139	0	(139)
8	Transmission (350-1000 kVA)		22	6	12	1	0	0	0	0	0	0	0	0	3	0	0	0	(0)
9	Primary (350-1000 kVA)		7,046	1,892	4,061	299	237	499	3	0	0	0	0	0	77	0	8	0	(31)
10	Secondary (350-1000 kVA)		23,998	6,221	13,281	982	780	1,640	14	615	9	442	3	0	77	0	36	0	(101)
11	Total (110-1000 kVA)	2.3	62,766	16,237	34,692	2,562	2,036	4,279	72	1,379	44	991	17	43	502	0	189	0	(277)
	(1000 kVA and Over)	2.4																	
12	Transmission		1,002	251	593	40	0	0	0	0	0	0	0	0	6	0	0	117	(4)
13	Primary		21,366	5,523	12,894	872	645	1,357	3	0	0	0	0	0	82	0	7	74	(89)
14	Secondary		5,899	1,477	3,429	233	173	363	2	136	1	98	0	0	10	0	4	0	(26)
15	Total (1000 kVA and Over)	2.4	28,267	7,250	16,916	1,144	818	1,719	4	136	1	98	0	0	98	0	12	191	(119)
16	**STREET LIGHTING**	4.1	11,663	964	1,444	152	100	211	675	79	148	57	169	0	0	7,445	265	0	(46)
17	Total		470,961	122,485	205,800	19,329	13,655	28,704	16,039	10,024	3,685	7,201	4,024	9,010	3,833	7,445	21,399	191	(1,862)

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ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE (Excluding RSA, MTA and Rural Deficit)

NOTES:

Line No.	Category	
17	Total	Total Cost of Service shown in Schedule 1.1, Line 12.

Col.		
A	Produced and Purchased Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
B	Produced and Purchased Energy	Transmission Energy Allocator taken From Schedule 4.4, Column L.
C	Transmission Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
D	Distribution Substation Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
E	Distribution Primary Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
F	Distribution Primary Customer	Primary Lines Customer Allocator taken from Schedule 4.3, Column G.
G	Distribution Transformer Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
H	Distribution Transformer Customer	Transformer Customer Allocator taken from Schedule 4.3, Column M.
I	Distribution Secondary Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
J	Distribution Secondary Customer	Secondary Lines Customer Allocator taken from Schedule 4.3, Column J.
K	Distribution Services Customer	Service Drop Allocator taken from Schedule 4.3, Column P.
L	Distribution Meters Customer	Meters Allocator taken from Schedule 4.3, Column S.
M	Distribution Street Lighting Customer	All Allocated to Street Lighting Rate Class.
N	Cust. Accounting and Cust. Services	Customer Allocator taken from Schedule 4.3, Column D.
O	Specifically Assigned	Total cost are allocated to class based on the amount of fixed plant dedicated to supplying single customers and the class which those customers belong.
P	Revenue Related	Total cost is allocated based on revenue from class plus RSA and MTA revenue, Column I, from Schedule 1.4.

TOTAL ALLOCATION OF THE COST OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Energy A	Demand B	Customer C	Street Lighting D	Specifically Assigned E	Revenue Related Expenses F	Total before RSA, MTA and Rural Deficit G	Allocated Rural Subsidy H	MTA I	RSA J	Total Cost to Serve K	Allocation of Other Revenue L	Total Cost Recovered in Final Rates M
	DOMESTIC														
1	Domestic Regular	1.1	31,753	33,698	19,692	0	0	(312)	84,831	6,543	2,073	3,131	96,578	$1,621	$94,957
2	Domestic All Electric	1.1	92,090	101,524	29,101	0	0	(826)	221,890	17,114	5,420	7,956	252,381	$4,298	$248,083
3	Total Domestic	1.1	123,844	135,221	48,794	0	0	(1,138)	306,721	23,657	7,494	11,086	348,958	$5,919	$343,039
	GENERAL SERVICE														
4	(0-10 kW)	2.1	3,513	3,023	3,121	0	0	(44)	9,614	742	291	344	10,991	$230	$10,761
5	(10-100 kW)	2.2	25,391	22,941	3,835	0	0	(237)	51,930	4,005	1,576	2,390	59,902	$1,232	$58,670
	(110-1000 kVA)	2.3													
6	Primary (110-350 kVA)		823	593	55	0	0	(7)	1,465	113	44	82	1,704	$34	$1,670
7	Secondary (110-350 kVA)		16,515	13,279	580	0	0	(139)	30,235	2,332	930	1,604	35,101	$720	$34,382
8	Transmission (350-1000 kVA)		12	7	3	0	0	(0)	22	2	1	1	25	$0	$24
9	Primary (350-1000 kVA)		4,061	2,927	89	0	0	(31)	7,046	543	201	422	8,213	$158	$8,055
10	Secondary (350-1000 kVA)		13,281	10,679	139	0	0	(101)	23,998	1,851	677	1,360	27,887	$516	$27,371
11	Total (110-1000 kVA)	2.3	34,692	27,484	867	0	0	(277)	62,766	4,841	1,854	3,469	72,930	$1,428	$71,503
	(1000 kVA and Over)	2.4													
12	Transmission		593	291	6	0	117	(4)	1,002	77	31	71	1,181	$21	$1,160
13	Primary		12,894	8,396	92	0	74	(89)	21,366	1,648	665	1,363	25,042	$455	$24,587
14	Secondary		3,429	2,478	17	0	0	(26)	5,899	455	190	357	6,901	$131	$6,770
15	Total (1000 kVA and Over)	2.4	16,916	11,165	115	0	191	(119)	28,267	2,180	886	1,791	33,125	$607	$32,517
16	**STREET LIGHTING**	4.1	1,444	1,562	1,257	7,445	0	(46)	11,663	900	312	171	13,045	$247	$12,798
17	Total		205,800	201,397	57,989	7,445	191	(1,862)	470,961	36,325	12,413	19,252	538,951	$9,663	$529,288

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TOTAL ALLOCATION OF THE COST OF SERVICE

NOTES:

Column

A	Energy cost taken from Schedule 1.2, Column B.
B	Demand cost taken from Schedule 1.2, as the sum of Columns A, C, D, E, G and I.
C	Customer cost taken from Schedule 1.2, as the sum of Columns F, H, J, K, L and N.
D	Direct Street Lighting Cost taken from Schedule 1.2, Column M.
E	Specifically assigned cost taken from Schedule 1.2, Column O.
F	Revenue Related Expenses taken from Schedule 1.2, Column P.
G	Sum of Columns A through F.
H	Rural Surcharge allocated to Class based on total cost before Rural Deficit, RSA & MTA, Column G.
I	MTA cost taken as equal to MTA revenue as taken from Schedule 1.4 Column G.
J	RSA cost taken as equal to revenue from RSA factor from Schedule 1.4 Column F.
K	Sum of Columns G through J.
L	Taken from the sum of Schedule 1.4, Column C.
M	Column K less Column L.

REVENUE BY CLASS OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Base Rates: Base Rates A	Revenue from Base Rates: Forfeited Discounts B	Allocation of Other Revenue C	Remove Rural Subsidy D	Total Before Rural Subsidy E	RSA Revenue F	MTA Revenue G	Rural Subsidy H	Total Revenue + RSA & MTA I	Total Revenue from Final Rates J
	DOMESTIC											
1	Domestic Regular	1.1	82,965	529	1,621	(6,543)	78,572	$3,131	$2,073	$6,543	$90,319	$88,698
2	Domestic All Electric	1.1	219,951	1,383	4,298	(17,114)	208,518	$7,956	$5,420	$17,114	$239,008	$234,711
3	Total Domestic		302,916	1,912	5,919	(23,657)	287,090	11,086	7,494	23,657	329,327	$323,408
	GENERAL SERVICE											
4	(0-10 kW)	2.1	11,742	86	230	(742)	11,316	$344	$291	$742	$12,693	$12,463
5	(10-100 kW)	2.2	63,129	327	1,232	(4,005)	60,683	$2,390	$1,576	$4,005	$68,655	$67,422
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		1,732	6	34	(113)	1,659	$82	$44	$113	$1,898	$1,864
7	Secondary (110-350 kVA)		36,939	135	720	(2,332)	35,462	$1,604	$930	$2,332	$40,329	$39,609
8	Transmission (350-1000 kVA)		23	0	0	(2)	22	$1	$1	$2	$25	$25
9	Primary (350-1000 kVA)		8,113	24	158	(543)	7,752	$422	$201	$543	$8,919	$8,761
10	Secondary (350-1000 kVA)		26,454	99	516	(1,851)	25,217	$1,360	$677	$1,851	$29,105	$28,590
11	Total (110-1000 kVA)	2.3	73,260	264	1,428	(4,841)	70,111	3,469	1,854	4,841	80,275	$78,847
	(1000 kVA and Over)	2.4										
12	Transmission		1,097	5	21	(77)	1,046	$71	$31	$77	$1,225	$1,204
13	Primary		23,392	32	455	(1,648)	22,231	$1,363	$665	$1,648	$25,907	$25,452
14	Secondary		6,719	20	131	(455)	6,415	$357	$190	$455	$7,417	$7,286
15	Total (1000 kVA and Over)	2.4	31,208	57	607	(2,180)	29,692	1,791	886	2,180	34,549	$33,942
16	**STREET LIGHTING**	4.1	12,722	0	247	(900)	12,070	$171	$312	$900	$13,452	$13,205
17	Total		494,977	2,646	9,663	(36,325)	470,961	19,252	12,413	36,325	538,951	$529,288

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REVENUE BY CLASS OF SERVICE

NOTE:

Column

A - From Booked Revenue and Bill Frequency Analysis.

B - From Booked Revenue and Bill Frequency Analysis.

C - Includes Amortizations, Adjustments, Transfers and Other Revenue as reported in Return 14 of annual Report to Board less Expense Credit from Schedule 5.2 Reconcillation of Expenses. Total Allocated to Customer Class based on the Totals for Column A plus B.

D - The rural deficit cost is removed from revenue by allocating the cost to each customer class based on class cost as shown on Schedule 1.3 Column H.

E - Total of Columns A through D.

F - From actual MTA booked and Bill Frequency Analysis.

G - From actual RSA booked and Bill Frequency Analysis.

H - From Column D.

I - Total of Columns E through H.

J - Column I less Column C.

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REVENUE TO COST RATIO
Including RSA, MTA and Rural Subsidy
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	323,408	343,039	94.3%
	GENERAL SERVICE				
2	(0-10 kW)	2.1	12,463	10,761	115.8%
3	(10-100 kW)	2.2	67,422	58,670	114.9%
4	(110 - 1000 kVA)	2.3	78,847	71,503	110.3%
5	(1000 kVA and Over)	2.4	33,942	32,517	104.4%
6	**STREET LIGHTING**	4.1	13,205	12,798	103.2%
7	Total		529,288	529,288	100.0%

Column
A Revenue from Schedule 1.4, Column J.
B Costs from Schedule 1.3, Column M.
C Column A divided by Column B.

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CLASSIFIED COST LOADERS BY CLASS

Line No.	Class of Service	Rate Code	Rural Subsidy A	Revenue Related Costs B	Non-Rate Revenue Recovery C	MTA D	Total Costs in Loader E	Total Classified Costs F	% Rate Loader G	RSA H	Sales MWh I	RSA cents/kWh J
			% Loader to be assigned to each Classified Cost Component							RSA Cost Loader (cents/kWh)		
	DOMESTIC											
1	Domestic Regular	1.1	6,543	(312)	(1,621)	2,073	6,683	85,143	7.85%	3,131	802,600	0.390
2	Domestic All Electric	1.1	17,114	(826)	(4,298)	5,420	17,411	222,716	7.82%	7,956	2,327,700	0.342
3	Total Domestic	1.1	23,657	(1,138)	(5,919)	7,494	24,094	307,859	7.83%	11,086	3,130,300	0.354
	GENERAL SERVICE											
4	(0-10 kW)	2.1	742	(44)	(230)	291	759	9,658	7.86%	344	88,800	0.387
5	(10-100 kW)	2.2	4,005	(237)	(1,232)	1,576	4,112	52,167	7.88%	2,390	641,800	0.372
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		113	(7)	(34)	44	116	1,471	7.92%	82	21,069	0.391
7	Secondary (110-350 kVA)		2,332	(139)	(720)	930	2,403	30,374	7.91%	1,604	417,431	0.384
8	Transmission (350-1000 kVA)		2	(0)	(0)	1	2	22	7.90%	1	326	0.157
9	Primary (350-1000 kVA)		543	(31)	(158)	201	556	7,077	7.86%	422	103,984	0.406
10	Secondary (350-1000 kVA)		1,851	(101)	(516)	677	1,912	24,099	7.93%	1,360	335,691	0.405
11	Total (110-1000 kVA)	2.3	4,841	(277)	(1,428)	1,854	4,990	63,043	7.91%	3,469	878,500	0.395
	(1000 kVA and Over)	2.4										
12	Transmission		77	(4)	(21)	31	83	1,006	8.24%	71	15,516	0.456
13	Primary		1,648	(89)	(455)	665	1,768	21,456	8.24%	1,363	330,113	0.413
14	Secondary		455	(26)	(131)	190	488	5,925	8.24%	357	86,671	0.412
15	Total (1000 kVA and Over)	2.4	2,180	(119)	(607)	886	2,340	28,387	8.24%	1,791	432,300	0.414
16	**STREET LIGHTING**	4.1	900	(46)	(247)	312	918	11,709	7.84%	171	36,500	0.469
17	Total		36,325	(1,862)	(9,663)	12,413	37,213	472,823	7.87%	19,252	5,208,200	0.370

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CLASSIFIED COST LOADERS BY CLASS

NOTE:

Column

A - See Schedule 1.3, Column H.
B - See Schedule 1.3, Column F.
C - See Schedule 1.3, Column L. (Negative).
D - See Schedule 1.3, Column I.
E - Total of Columns A through D.
F - See Schedule 1.3, Sum of Columns A through E.
G - Column E divided by Column F.
H - See Schedule 1.3, Column J.
I - See Schedule 4.1, Column D.
J - Column H divided by Column I.

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UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

			Billing Statistics From Schedule 4.1				Unit Demand Costs		Unit Customer Costs			
Line No.	Class of Service	Rate Code	Energy Sales MWh A	Average Number of Customers B	Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	By Energy Sales cent/kWh E	By Billing Demand $/kW - $/kVA F	By Energy Sales cent/kWh G	By Number of Customers $/Cust/month H	Specifically Assigned / Street Lighting Cost by Sales cent/kWh I	Total Cost by Sales cent/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	802,600	81,776	0	4.657	4.528	0.00	2.646	21.64	0.000	11.831
2	Domestic All Electric	1.1	2,327,700	120,849	0	4.607	4.703	0.00	1.348	21.64	0.000	10.658
3	Total Domestic	1.1	3,130,300	202,625	0	4.620	4.658	0.00	1.681	21.64	0.000	10.959
	GENERAL SERVICE											
4	(0-10 kW)	2.1	88,800	11,873	0	4.655	3.672	0.00	3.791	23.63	0.000	12.118
5	(10-100 kW)	2.2	641,800	8,568	2,311,746	4.641	3.856	10.71	0.645	40.24	0.000	9.141
	(110-1000 kVA)	2.3										
6	Primary (110-350 kVA)		21,069	28	57,312	4.606	3.038	11.17	0.282	177.13	0.000	7.926
7	Secondary (110-350 kVA)		417,431	774	1,363,275	4.654	3.433	10.51	0.150	67.44	0.000	8.236
8	Transmission (350-1000 kVA)		326	1	756	4.281	2.198	9.47	1.009	273.77	0.000	7.487
9	Primary (350-1000 kVA)		103,984	45	276,987	4.619	3.036	11.40	0.092	177.04	0.000	7.747
10	Secondary (350-1000 kVA)		335,691	201	946,201	4.675	3.433	12.18	0.045	62.41	0.000	8.154
11	Total (110-1000 kVA)	2.3	878,500	1,049	2,644,531	4.657	3.376	11.22	0.106	74.30	0.000	8.139
	(1000 kVA and Over)	2.4										
12	Transmission		15,516	2	40,196	4.592	2.027	7.83	0.042	274.62	0.814	7.476
13	Primary		330,113	40	788,950	4.641	2.753	11.52	0.030	207.41	0.024	7.448
14	Secondary		86,671	24	264,088	4.694	3.095	10.16	0.022	65.13	0.000	7.811
15	Total (1000 kVA and Over)	2.4	432,300	66	1,093,234	4.650	2.796	11.05	0.029	157.71	0.048	7.522
16	**STREET LIGHTING**	4.1	36,500	9,842	0	4.736	4.616	0.00	3.715	11.48	21.997	35.064
17	Total		5,208,200	234,023	6,049,511	4.632	4.171		1.201	22.27	0.158	10.163

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UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

NOTE:

Column

A - See Schedule 4.1, Column D.
B - See Schedule 4.1, Column C.
C - See Schedule 4.1, Column E.
D - [(Total of Energy Related Costs (Schedule 1.3, Column A) divided by Energy Sales (Schedule 1.7, Column A)) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100] plus RSA Loader (Schedule 1.6, Column J).
E - Demand Related Costs (Schedule 1.3, Column B) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
F - Demand Related Costs (Schedule 1.3, Column B) divided by Total Billing Demands (Schedule 1.7, Column C) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000.
G - Customer Related Costs (Schedule 1.3, Column C) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
H - Customer Related Costs (Schedule 1.3, Column C) divided by Average Number of Customers (Schedule 1.7, Column B) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000 divided by 12.
I - Specifically Assigned Costs (Schedule 1.3 Column E) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
J - Total of Columns D, E, G and I.

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS
(All numbers are times $1,000)

Line No. Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1 Hydro Electric Production	137,363	62,624	74,739	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Other Generation	21,002	21,002	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Transmission	98,242	0	0	97,442	0	0	0	0	0	0	0	0	0	0	0	800
Substations																
4 Hydro Electric Production	6,879	3,136	3,743	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Other Production	815	815	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Transmission	41,926	0	0	41,684	0	0	0	0	0	0	0	0	0	0	0	242
7 Distribution	88,249	0	0	0	87,918	0	0	0	0	0	0	0	0	0	0	330
Distribution																
8 Land and Land Clearing	906	0	0	0	0	444	250	0	0	111	62	0	0	38	0	0
9 Conductors, Poles and Fittings	531,202	0	0	0	0	260,537	146,552	0	0	65,134	36,638	0	0	22,341	0	0
10 Transformers	94,242	0	0	0	0	0	0	68,797	25,445	0	0	0	0	0	0	0
11 Services	73,554	0	0	0	0	0	0	0	0	0	0	73,554	0	0	0	0
12 Meters	21,620	0	0	0	0	0	0	0	0	0	0	0	21,620	0	0	0
13 Street lighting	18,153	0	0	0	0	0	0	0	0	0	0	0	0	18,153	0	0
14 Total Direct Utility Plant	1,134,154	87,577	78,482	139,126	87,918	260,981	146,802	68,797	25,445	65,245	36,700	73,554	21,620	40,532	0	1,373
General Utility Plant																
15 Land and Land Clearing	4,823	135	121	784	295	876	493	231	85	219	123	247	73	136	997	7
16 Buildings	33,652	1,341	1,202	5,569	2,058	6,110	3,437	1,611	596	1,528	859	1,722	506	949	6,114	49
17 Computer Equipment	40,894	1,853	1,661	3,252	1,359	4,035	2,270	1,064	393	1,009	567	1,137	334	627	21,305	29
18 Misc Equipment	16,280	638	572	3,133	1,022	3,034	1,706	800	296	758	427	855	251	471	2,290	27
19 Transportation	22,249	564	505	2,944	1,770	5,253	2,955	1,385	512	1,313	739	1,481	435	816	1,548	29
20 Tele-communications	10,562	894	801	1,711	634	1,881	1,058	496	183	470	264	530	156	292	1,176	15
21 Total General Utility Plant	128,462	5,426	4,862	17,394	7,138	21,189	11,919	5,586	2,066	5,297	2,980	5,972	1,755	3,291	33,430	157
22 Total	1,262,616	93,003	83,344	156,520	95,056	282,170	158,721	74,382	27,511	70,543	39,680	79,526	23,375	43,823	33,430	1,530

Newfoundland Power Inc.
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FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
14	Total Direct Fixed Plant	Total of Lines 1 through 13.
	General Utility Plant	
15	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
21	Total General Property	Total of Lines 15 through 20.
22	Total	Total of Lines 14 and 21.

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	41,423	18,885	22,538	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	8,054	8,054	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	49,889	0	0	49,482	0	0	0	0	0	0	0	0	0	0	0	406
	Substations																
4	Hydro Electric Production	2,674	1,219	1,455	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	317	317	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	16,297	0	0	16,203	0	0	0	0	0	0	0	0	0	0	0	94
7	Distribution	34,304	0	0	0	34,176	0	0	0	0	0	0	0	0	0	0	128
	Distribution																
8	Land and Land Clearing	652	0	0	0	0	319	180	0	0	80	45	0	0	29	0	0
9	Conductors, Poles and Fittings	217,569	0	0	0	0	106,526	59,921	0	0	26,631	14,980	0	0	9,512	0	0
10	Transformers	25,160	0	0	0	0	0	0	18,367	6,793	0	0	0	0	0	0	0
11	Services	54,272	0	0	0	0	0	0	0	0	0	0	54,272	0	0	0	0
12	Meters	8,114	0	0	0	0	0	0	0	0	0	0	0	8,114	0	0	0
13	Street lighting	8,757	0	0	0	0	0	0	0	0	0	0	0	0	8,757	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	12,978	517	463	2,148	794	2,356	1,326	621	230	589	331	664	195	366	2,358	19
16	Computer Equipment	23,097	1,047	938	1,837	768	2,279	1,282	601	222	570	320	642	189	354	12,033	17
17	Misc. Equipment	8,138	319	286	1,566	511	1,516	853	400	148	379	213	427	126	236	1,145	14
18	Transportation	8,801	223	200	1,165	700	2,078	1,169	548	203	520	292	586	172	323	612	11
19	Tele-communications	7,574	641	575	1,227	454	1,349	759	356	131	337	190	380	112	209	844	11
20	Total	528,072	31,222	26,455	73,628	37,402	116,423	65,488	20,891	7,727	29,106	16,372	56,972	8,908	19,785	16,991	701

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Rights	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	1,148	0	0	1,139	0	0	0	0	0	0	0	0	0	0	0	9
	Substations																
4	Hydro Electric Production	66	30	36	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	399	0	0	397	0	0	0	0	0	0	0	0	0	0	0	2
7	Distribution	841	0	0	0	837	0	0	0	0	0	0	0	0	0	0	3
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	19,653	0	0	0	0	9,639	5,422	0	0	2,410	1,356	0	0	827	0	0
10	Transformers	1,384	0	0	0	0	0	0	1,010	374	0	0	0	0	0	0	0
11	Services	746	0	0	0	0	0	0	0	0	0	0	746	0	0	0	0
12	Meters	570	0	0	0	0	0	0	0	0	0	0	0	570	0	0	0
13	Street lighting	349	0	0	0	0	0	0	0	0	0	0	0	0	349	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Computer Equipment	(113)	(5)	(5)	(9)	(4)	(11)	(6)	(3)	(1)	(3)	(2)	(3)	(1)	(2)	(59)	(0)
17	Misc. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tele-communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total	25,050	33	31	1,527	834	9,628	5,416	1,007	373	2,407	1,354	743	569	1,174	(59)	15

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

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FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	
1	Hydro Electric Production	95,940	43,739	52,201	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	12,948	12,948	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	48,354	0	0	47,960	0	0	0	0	0	0	0	0	0	0	0	394	0
	Substations																	
4	Hydro Electric Production	4,205	1,917	2,288	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	498	498	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	25,629	0	0	25,481	0	0	0	0	0	0	0	0	0	0	0	148	0
7	Distribution	53,945	0	0	0	53,743	0	0	0	0	0	0	0	0	0	0	202	0
	Distribution																	
8	Land and Land Clearing	254	0	0	0	0	125	70	0	0	31	18	0	0	10	0	0	0
9	Conductors, Poles and Fittings	313,635	0	0	0	0	154,013	86,631	0	0	38,503	21,658	0	0	12,829	0	0	0
10	Transformers	69,083	0	0	0	0	0	0	50,430	18,652	0	0	0	0	0	0	0	0
11	Services	19,282	0	0	0	0	0	0	0	0	0	0	19,282	0	0	0	0	0
12	Meters	13,505	0	0	0	0	0	0	0	0	0	0	0	13,505	0	0	0	0
13	Street lighting	9,396	0	0	0	0	0	0	0	0	0	0	0	0	9,396	0	0	0
14	Total Direct Net Utility Plant	666,673	59,103	54,489	73,440	53,743	154,138	86,702	50,430	18,652	38,534	21,675	19,282	13,505	22,235	0	744	0
	General Plant																	
15	Land and Land Rights	4,823	135	121	784	295	876	493	231	85	219	123	247	73	136	997	7	0
16	Buildings	20,674	824	738	3,422	1,265	3,754	2,112	990	366	938	528	1,058	311	583	3,756	30	0
17	Computer Equipment	17,797	806	723	1,415	592	1,756	988	463	171	439	247	495	145	273	9,272	13	0
18	Misc. Equipment	8,142	319	286	1,567	511	1,517	853	400	148	379	213	428	126	236	1,145	14	0
19	Transportation	13,449	341	305	1,780	1,070	3,175	1,786	837	310	794	447	895	263	493	936	17	0
20	Tele-communications	2,988	253	227	484	179	532	299	140	52	133	75	150	44	83	333	4	0
21	Total General Plant	67,873	2,679	2,400	9,452	3,911	11,611	6,531	3,061	1,132	2,903	1,633	3,272	962	1,803	16,439	86	0
22	Total Net Utility Plant	734,546	61,781	56,890	82,892	57,654	165,749	93,233	53,491	19,784	41,437	23,308	22,554	14,467	24,038	16,439	829	0
	Deductions from Rate Base																	
23	Contributions in Aid of Construction	25,050	33	31	1,527	834	9,628	5,416	1,007	373	2,407	1,354	743	569	1,174	(59)	15	0
24	MTA Liability	3,408	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,408
25	2005 Unbilled Revenue Liability	12,841	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,841
26	Security Deposits	699	50	43	69	53	104	59	26	10	26	15	52	15	29	148	1	0
27	Accrued Pension Liability	3,043	218	187	302	232	454	255	114	42	113	64	225	65	125	643	3	0
28	Future Income Taxes - Depreciation/CCA	288	24	22	32	23	65	36	21	8	16	9	9	6	9	6	0	0
29	Future Income Taxes - Pension/OPEBS	305	22	19	30	23	45	26	11	4	11	6	23	7	13	64	0	0
30	DMI and PPUCV Liability	1,486	1,486	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Total Deductions	47,118	1,832	302	1,961	1,165	10,296	5,792	1,180	436	2,574	1,448	1,050	661	1,350	802	19	16,249
	Additions to Rate Base																	
32	Average Deferred Charges	98,787	7,076	6,074	9,805	7,541	14,737	8,289	3,697	1,367	3,684	2,072	7,304	2,112	4,067	20,870	92	0
33	Deferred Energy Replacement Costs	957	0	957	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Unamortized True-up Deferral	9,655	692	594	958	737	1,440	810	361	134	360	203	714	206	397	2,040	9	0
35	Customer Financing Programs	1,794	128	110	178	137	268	150	67	25	67	38	133	38	74	379	2	0
36	Weather Normalization (hydro equal.)	2,606	0	2,606	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Weather Normalization (Degree Day Norm.)	5,608	665	613	893	621	1,785	0	576	0	446	0	0	0	0	0	9	0
38	Cash Working Capital Allowance	9,716	3,071	5,384	131	112	177	100	44	16	44	25	112	33	63	407	1	(4)
39	Materials And Supplies	4,327	176	158	1,462	268	795	447	209	77	199	112	224	66	123	0	12	0
40	Total Additions	133,448	11,808	16,494	13,426	9,415	19,201	9,797	4,955	1,619	4,800	2,449	8,486	2,455	4,725	23,696	124	(4)
41	Total Average Rate Base	820,876	71,758	73,081	94,357	65,904	174,654	97,238	57,266	20,968	43,663	24,309	29,990	16,261	27,412	39,332	935	(16,253)

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FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
2	Other Generation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
3	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
	Substations	
4	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
5	Other Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
6	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
7	Distribution	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Distribution	
8	Land and Land Clearing	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
9	Conductors, Poles and Fittings	
10	Transformers	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
11	Services	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
12	Meters	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
13	Street lighting	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
14	Total Direct Net Utility Plant	Total of Line 1 to 13.
	General Plant	
15	Land and Land Rights	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
16	Buildings	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
17	Computer Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
18	Misc. Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
19	Transportation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
20	Tele-communications	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
21	Total General Plant	Total of Lines 15 to 20.
22	Total Net Utility Plant	Total of Line 14 and Line 21.
	Deductions from Rate Base	
23	Contributions in Aid of Construction	Taken from totals shown on Schedule 2.3.
24	MTA Liability	Assigned as Revenue Related Liability.
25	2005 Unbilled Revenue Liability	Assigned as Revenue Related Liability.
26	Security Deposits	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
27	Accrued Pension Liability	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
28	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
29	Future Income Taxes - Pension/OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
30	DMI and PPUCV Liability	Functional Classification Classified 100% to Produced and Purchased Demand.
31	Total Deductions	Total of Lines 23 through 30.
	Additions to Rate Base	
32	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
33	Deferred Energy Replacement Costs	Classified 100% to Energy
34	Unamortized Regulation Cost Deferral	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
35	Customer Financing Programs	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
36	Weather Normalization (hydro equal.)	Classified 100% to Energy.
37	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions
38	Cash Working Capital Allowance	Functional Classification based on total operating and maintenance shown on Schedule 1.1, line 1 plus line 2.
39	Materials And Supplies	Functionalized based on Year End Inventory (See Schedule 5.1 Line 31). Classification based on total direct utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned (Schedule 2.1).
40	Total Additions	Total of Lines 32 through 39.
41	Total Rate Base	Line 22 less Line 31 plus Line 40.

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses			Non-Regulated	Excluding Non-Regulated Expenses		
		Total	Labour	Non-Labour	Expenses	Total Excl.	Labour Excl.	Non-Labour Excl.
	PURCHASED POWER WEATHER ADJUSTED							
PPH	Nfld. Hydro - Firm	336,651	-	336,651	-	336,651	-	336,651
PPDL	Nfld. Hydro - Secondary	7	-	7	-	7	-	7
	TOTAL PURCHASED POWER	336,658	-	336,658	-	336,658	-	336,658
	PRODUCTION							
Hydro	Hydro - Direct Operating and Maintenance	1,508	977	531	-	1,508	977	531
Hydro	Hydro - Water and Fuel - Lubricants	101	-	101	-	101	-	101
Hydro	Hydro - Supervision and misc.	496	396	100	-	496	396	100
Oth Prod	Other Production - Direct Operating and Maintenance	361	235	126	-	361	235	126
Oth Prod	Other Production - Fuel and Lubricants	86	-	86	-	86	-	86
	TOTAL PRODUCTION	2,552	1,608	944	-	2,552	1,608	944
Gen Sys Opr	SYSTEM OPERATIONS	1,150	1,045	105	-	1,150	1,045	105
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	604	14	590	-	604	14	590
Gen PTD	GENERAL OPERATIONS	2,866	2,488	378	6	2,860	2,483	378
Gen TD	OPERATING SUPERVISION	$0	$0	$0	-	-	-	-
	TOTAL MISC TECHNICAL OPERATING COSTS	4,620	3,547	1,073	6	4,614	3,542	1,073
Gen PTD	ENVIRONMENTAL COST	398	255	143	-	398	255	143
	SUBSTATIONS							
Subs	Direct O&M	2,136	1,497	639	-	2,136	1,497	639
	TRANSMISSION							
Transm	Direct O&M	614	268	346	-	614	268	346
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	2,090	1,872	218	-	2,090	1,872	218
Services	Direct O&M - Services	1,526	1,496	31	-	1,526	1,496	31
Strlgts	Direct O&M - Street Lights	857	662	195	-	857	662	195
Transf.	Direct O&M - Transformers	286	264	23	-	286	264	23
Meters	Direct O&M - Meters	435	324	111	-	435	324	111
Gen D	Direct O&M - Vegetation Management	1,183	131	1,052	-	1,183	131	1,052
Gen D	Power Quality	12	10	2	-	12	10	2
Gen D	Pre Issues	160	-	160	-	160	-	160
	TOTAL DISTRIBUTION	6,549	4,759	1,791	-	6,549	4,759	1,791

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LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Including Non-Regulated Expenses Labour	Including Non-Regulated Expenses Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Excluding Non-Regulated Expenses Labour Excl.	Excluding Non-Regulated Expenses Non-Labour Excl.
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,352	23	1,329	-	1,352	23	1,329
Gen Comm	Direct O&M - Supervisory Contol Systems	36	30	6	-	36	30	6
	TOTAL COMMUNICATIONS	1,388	53	1,335	-	1,388	53	1,335
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	4,216	3,791	425	29	4,187	3,765	422
Cust Acc	Credit, Collections & Cash Control	2,340	819	1,521		2,340	819	1,521
Cust Acc	Inquiry	2,485	2,471	13		2,485	2,471	13
Cust Acc	Uncollectable Bills	834	-	834	-	834	-	834
A&G	Energy Services - General CDM Programs	1,121	405	716		1,121	405	716
	TOTAL CUSTOMER SERVICE	10,996	7,486	3,510	29	10,967	7,460	3,507
	FINANCE							
A&G	Finance	1,175	979	196		1,175	979	196
Labour Rela	Company Pension Scheme	2,713	-	2,713		2,713	-	2,713
Labour Rela	Retirement Allowances	307	-	307		307	-	307
Ins & Dam.	Risk Management	136	108	28	-	136	108	28
	TOTAL FINANCE	4,331	1,087	3,244	-	4,331	1,087	3,244
	CORPORATE COMMUNICATIONS							
A&G	Corporate Communications Supervision, Misc. and General Advertisments	881	445	437	50	831	419	412
	TOTAL CORPORATE COMMUNICATIONS	881	445	437	50	831	419	412
	MANAGEMENT INFORMATION SYSTEMS							
A&G	Supervision & Misc.	285	214	71	-	285	214	71
A&G	Computer Operations	625	563	62	-	625	563	62
A&G	Systems Development and Support	1,576	651	926	-	1,576	651	926
	TOTAL MIS	2,487	1,428	1,059	-	2,487	1,428	1,059
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	1,354	1,030	324	-	1,354	1,030	324
A&G	Employee Welfare & Coffee & Lunchroom Supplies	299	66	233	13	287	63	224
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	1,654	1,096	557	13	1,641	1,093	548
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	6,361	3,889	2,471	1,041	5,320	3,253	2,067
A&G	Misc. Costs - General	1,110	602	507	358	751	408	344
Ins & Dam.	Misc. Costs - Property Insurace & Public Liability (Not Insured)	1,521	-	1,521	-	1,521	-	1,521
Cust Acc	Mail Room	24	-	24	-	24	-	24

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC) (Excluding RSA and MTA)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses			Non-Regulated	Excluding Non-Regulated Expenses		
		Total	Labour	Non-Labour	Expenses	Total Excl.	Labour Excl.	Non-Labour Excl.
Revenue Related	PUB Assessments	(138)	-	(138)	-	(138)	-	(138)
A&G	Property Maintenance	1,153	117	1,035	-	1,153	117	1,035
A&G	Printing Services	226	161	65	-	226	161	65
	TOTAL ADMINISTRATION & MISCELLANEOUS	10,256	4,770	5,486	1,399	8,857	3,939	4,918
Vehicles	VEHICLE MAINTENANCE	1,572	-	1,572	-	1,572	-	1,572
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	387,093	28,298	358,795	1,497	385,597	27,408	358,189

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
Curtail	Curtailable Credits Paid Customers.
CPF	Operating expenses directly associated with Conductors, Poles and Fittings.
Cust Acc	Operating Expenses associated with Customer Accounting and Customer Service.
Gen Comm	Communication Expenses Related to the VHS/Mobile radio system.
Gen D	General expenses to be split over the categories within distribution.
Gen PTD	General expenses to be split over Production, Transmission and Distribution.
Gen Sys Opr	General expenses associated with the Systems Control Centre.
Gen TD	General expenses to be split over Transmission and Distribution.
Hydro	Operating expenses associated with Hydraulic Generation.
Labour Rela	Administration and general Expenses directly related to Labour.
Meters	Operating expenses directly associated with Meters.
Oth Prod	Operating expenses associated with Diesel and Gas Turbine Generation.
Ins & Dam.	Property Insurance, Public Liability, Risk Management.
PPDL	Purchase Power Costs for Secondary Energy from Deer Lake Power Firmed up by Hydro.
PPH	Purchase Power Costs from Hydro for Firm Energy.
Revenue Related	Operating expenses related to revenue.
Services	Operating expenses directly associated with Services.
Strlgts	Operating expenses directly associated with Street Lighting.
Subs	Operating expenses directly associated with Substations.
Transf.	Operating expenses directly associated with Transformers.
Transm	Operating expenses directly associated with Transmission.
Vehicles	Operating expenses directly associated with Vehicles.

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Catagory	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	274,198	81,711	192,487	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	26,128	26,128	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Deer Lake Power Secondary	7	2	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Sub Total	300,333	107,841	192,492	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Direct Operating & Maintenance Expense																	
5	Hydraulic Production	2,105	960	1,145	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Production	447	447	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Transmission	614	0	0	609	0	0	0	0	0	0	0	0	0	0	0	5	0
	Substations																	
8	Hydarulic Plants	107	49	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Other Production	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	650	0	0	646	0	0	0	0	0	0	0	0	0	0	0	4	0
11	Distribution	1,367	0	0	0	1,362	0	0	0	0	0	0	0	0	0	0	5	0
	Distribution																	
12	Lines/poles/fittings	2,090	0	0	0	0	1,070	602	0	0	267	150	0	0	0	0	0	0
13	Services	1,526	0	0	0	0	0	0	0	0	0	0	1,526	0	0	0	0	0
14	Street Lights	857	0	0	0	0	0	0	0	0	0	0	0	0	857	0	0	0
15	Transformers	286	0	0	0	0	0	0	209	77	0	0	0	0	0	0	0	0
16	Meters	435	0	0	0	0	0	0	0	0	0	0	0	435	0	0	0	0
17	Customer Accounting	9,870	0	0	0	0	0	0	0	0	0	0	0	0	0	9,870	0	0
18	Subtotal Direct O&M	20,367	1,468	1,203	1,255	1,362	1,070	602	209	77	267	150	1,526	435	857	9,870	14	0
	General System Expenses																	
19	Related to Distribution	1,354	0	0	0	197	347	195	86	32	87	49	196	57	109	0	1	0
20	Related to Prod, Trans. & Distribution	3,862	398	339	479	385	677	381	167	62	169	95	382	110	213	0	5	0
21	Related to Vehicles	1,572	40	36	208	125	371	209	98	36	93	52	105	31	58	109	2	0
22	System Control Centre Expenses	1,150	84	72	243	110	193	108	48	18	48	27	109	31	61	0	0	0
23	General Communication Expenses	1,388	94	80	238	110	194	109	48	18	48	27	110	32	61	219	0	0
24	Subtotal General System Expenses	9,327	616	526	1,167	927	1,782	1,002	446	165	445	251	902	261	502	328	8	0
	Administration and General																	
25	Insurance, Injuries & Damages	1,657	139	128	187	130	374	210	121	45	93	53	51	33	54	37	2	0
26	Labour Related	3,020	216	186	300	231	451	253	113	42	113	63	223	65	124	638	3	0
27	Other Administration And General Expenses	14,706	1,053	904	1,460	1,123	2,194	1,234	550	204	548	308	1,087	314	605	3,107	14	0
28	Amortization of True-up Deferral	3,862	277	237	383	295	576	324	145	53	144	81	286	83	159	816	4	0
29	PUB Assessments	(138)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(138)
30	Subtotal Administration and General Expenses	23,106	1,686	1,456	2,330	1,778	3,594	2,022	929	343	899	505	1,647	494	943	4,598	22	(138)
31	Total O&M (less RSA, MTA and Rural Deficit)	353,134	111,611	195,677	4,752	4,067	6,446	3,626	1,583	586	1,611	906	4,075	1,190	2,302	14,796	44	(138)

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FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES

Line No.	Category	Basis for Functional Classification
	Column A - Total	From Schedule 3.1 less rural deficit plus the amortization of deferred regualtory costs (related to depreciation)
	Purchase Power Expense	Excludes the rural deficit of $36,325,023
1	Purchases from Hydro - Production related	Based on functional classification splits shown in Schedule 5.1, Line 1. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
2	Purchases from Hydro - Transmission related	Based on functional classification splits shown in Schedule 5.1, Line 2. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
3	Deer Lake Power Secondary	Based on functional classification splits shown in Schedule 5.1, Line 3.
4	Sub Total	Total of Lines 1 - 3.
	Direct Operating & Maintenance Costs	
5	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
6	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
7	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
8	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
9	Other Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
10	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
11	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
12	Lines/poles/fittings	Functional splits based on schedule 5.1 line 22 (excluding street lighting) and classified as shown in schedule 5.1 lines 11 & 12.
13	Services	Classified as shown in schedule 5.1 line 15.
14	Street Lights	Classified as shown in schedule 5.1 line 17.
15	Transformers	Classified as shown in schedule 5.1 line 14.
16	Meters	Classified as shown in schedule 5.1 line 16.
17	Customer Accounting	Classified 100% to Customer Accounting (Customer).
18	Subtotal Direct O&M	Total of Lines, 5 to 17.
	General System Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Line 18). The weighting used is: 58.3% operating, and 41.7% capital.

	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	7.3%	6.2%	8.8%	7.0%	12.4%	7.0%	3.1%	1.1%	3.1%	1.7%	7.0%	2.0%	3.9%	29.4%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
19	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
20	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
21	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
22	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1). Classification based on functional categories shown for general system expenses in columns B through O.
23	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1). Classification based on functional categories shown for general system expenses in columns B through O.
24	Subtotal General System Expenses	Total of all Lines 19 to 23.
	Administration and General Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Lines 18 plus 24). The weighting used is: 58.3% operating, and 41.7% capital.

Split for Administration and General

	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	7.2%	6.1%	9.9%	7.6%	14.9%	8.4%	3.7%	1.4%	3.7%	2.1%	7.4%	2.1%	4.1%	21.1%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
25	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
26	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
27	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
28	Amortization of True-up Deferral	Functional Classification based on the Weighted Split for Administration and General.
29	PUB Assessments	Assigned 100% as Revenue Related.
30	Subtotal Administration and General	Total for Lines 25 to 29.
31	Total O&M	Totals of Lines 4, 18, 24 and 30.

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Primary Demand F	Primary Customer G	Transformers Demand H	Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	3,618	1,649	1,968	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	1,168	1,168	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	3,060	0	0	3,035	0	0	0	0	0	0	0	0	0	0	0	25
	Substations																
4	Hydro Electric Production	169	77	92	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	1,030	0	0	1,024	0	0	0	0	0	0	0	0	0	0	0	6
7	Distribution	2,168	0	0	0	2,160	0	0	0	0	0	0	0	0	0	0	8
	Distribution																
8	Land and Land Clearing	(11)	0	0	0	0	(5)	(3)	0	0	(1)	(1)	0	0	(0)	0	0
9	Conductors, Poles and Fittings	14,425	0	0	0	0	7,075	3,980	0	0	1,769	995	0	0	607	0	0
10	Transformers	2,772	0	0	0	0	0	0	2,023	748	0	0	0	0	0	0	0
11	Services	1,470	0	0	0	0	0	0	0	0	0	0	1,470	0	0	0	0
12	Meters	810	0	0	0	0	0	0	0	0	0	0	0	810	0	0	0
13	Street lighting	1,427	0	0	0	0	0	0	0	0	0	0	0	0	1,427	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	598	24	21	99	37	109	61	29	11	27	15	31	9	17	109	1
16	Computer Equipment	4,449	202	181	354	148	439	247	116	43	110	62	124	36	68	2,318	3
17	Misc. Equipment	723	28	25	139	45	135	76	36	13	34	19	38	11	21	102	1
18	Transportation	2,311	59	52	306	184	546	307	144	53	136	77	154	45	85	161	3
19	Tele-communications	443	38	34	72	27	79	44	21	8	20	11	22	7	12	49	1
20	Total	40,649	3,264	2,374	5,028	2,600	8,376	4,712	2,368	876	2,094	1,178	1,839	919	2,236	2,738	48

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

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CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2007	2008	Average	2008 Energy Sales kWh	2008 Total Billing Demands kW \ kVA	Non-coincident Maximum Class Demands (NCP): Estimated Class Load Factor	Class NCP Demand kW	Class Demand Coincident with System Peak (1CP): Estimated Class Load Factor	Class 1CP Demand kW
			A	B	C	D	E	F	G	H	I
	DOMESTIC										
1	Domestic Regular	1.1	82,275	81,276	81,776	802,600,000	0	43.0%	213,072	51.8%	176,875
2	Domestic All Electric	1.1	118,770	122,928	120,849	2,327,700,000	0	47.9%	554,737	46.8%	567,776
	GENERAL SERVICE										
3	(0-10 kW)	2.1	11,826	11,920	11,873	88,800,000	0	50.9%	19,915	65.2%	15,548
4	(10-100 kW)	2.2	8,509	8,626	8,568	641,800,000	2,311,746	52.6%	139,287	59.7%	122,722
	(110-350 kVA)	2.3									
5	Primary		28	28	28	21,069,336	57,312	56.7%	4,242	68.4%	3,516
6	Secondary		754	793	774	417,430,664	1,363,275	56.7%	84,042	68.4%	69,667
	(350-1000 kVA)	2.3									
7	Transmission		2	0	1	325,741	756	56.7%	66	68.4%	54
8	Primary		46	43	45	103,983,685	276,987	56.7%	20,935	68.4%	17,354
9	Secondary		205	197	201	335,690,574	946,201	56.7%	67,585	68.4%	56,025
	(1000 kVA and Over)	2.4									
10	Transmission		2	2	2	15,516,478	40,196	66.2%	2,676	74.4%	2,381
11	Primary		38	41	40	330,112,849	788,950	66.2%	56,925	74.4%	50,651
12	Secondary		26	22	24	86,670,672	264,088	66.2%	14,945	74.4%	13,298
13	**STREET LIGHTING**	4.1	9,781	9,902	9,842	36,500,000	0	48.0%	8,681	48.0%	8,681
14	Total		232,262	235,778	234,023	5,208,200,000	6,049,511	50.1%	1,187,108	53.8%	1,104,546

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ENERGY AND DEMAND LOSS FACTORS[1]

(Losses as a percentage of delivered)

Demand Loss Factors

Transmission	1.8611%
Primary	3.4209%
Secondary	3.3557%

Energy Loss Factors

Transmission	1.1541%
Primary	2.2115%
Secondary	2.8109%

(1) Based on a three year average (2006 to 2008)

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

Line No.	Class of Service	Rate Code	Average Number of Customers A	Customer Related Costs: Weighting Factor B	Customer Related Costs: Weighted Number of Customer C	Customer Related Costs: Allocation Factors D	Primary Lines: Weighting Factor E	Primary Lines: Weighted Number of Customer F	Primary Lines: Allocation Factors G	Secondary Lines: Weighting Factor H	Secondary Lines: Weighted Number of Customer I	Secondary Lines: Allocation Factors J	Transformers: Weighting Factor K	Transformers: Weighted Number of Customer L	Transformers: Allocation Factors M	Service Drops: Weighting Factor N	Service Drops: Weighted Number of Customer O	Service Drops: Allocation Factors P	Meters: Weighting Factor Q	Meters: Weighted Number of Customer R	Meters: Allocation Factors S
	DOMESTIC																				
1	Domestic Regular	1.1	81,776	1.0	81,776	34.359%	1.0	81,776	34.944%	1.0	81,776	34.961%	1.0	81,776	33.360%	1.0	81,776	36.344%	1.0	81,776	21.514%
2	Domestic All Electric	1.1	120,849	1.0	120,849	50.776%	1.0	120,849	51.640%	1.0	120,849	51.665%	1.0	120,849	49.299%	1.0	120,849	53.709%	1.0	120,849	31.794%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	11,873	1.1	13,060	5.487%	1.0	11,873	5.073%	1.0	11,873	5.076%	1.2	14,248	5.812%	1.0	11,873	5.277%	2.0	23,746	6.247%
4	(10-100 kW)	2.2	8,568	2.0	17,136	7.200%	1.0	8,568	3.661%	1.0	8,568	3.663%	1.8	15,422	6.291%	1.1	9,425	4.189%	11.0	94,248	24.796%
	(110-350 kVA)	2.3																			
5	Primary		28	2.0	56	0.024%	1.0	28	0.012%	-	-	0.000%	-	-	0.000%	-	-	0.000%	170.7	4,780	1.257%
6	Secondary		774	2.0	1,548	0.650%	1.0	774	0.331%	1.0	774	0.331%	3.0	2,322	0.947%	1.4	1,084	0.482%	38.0	29,412	7.738%
	(350-1000 kVA)	2.3																			
7	Transmission		1	2.0	2	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	284.1	284	0.075%
8	Primary		45	2.0	90	0.038%	1.0	45	0.019%	-	-	0.000%	-	-	0.000%	-	-	0.000%	170.7	7,682	2.021%
9	Secondary		201	2.0	402	0.169%	1.0	201	0.086%	1.0	201	0.086%	3.0	603	0.246%	-	-	0.000%	38.0	7,638	2.009%
	(1000 kVA and Over)	2.4																			
10	Transmission		2	2.0	4	0.002%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	284.1	568	0.149%
11	Primary		40	2.0	80	0.034%	1.0	40	0.017%	-	-	0.000%	-	-	0.000%	-	-	0.000%	203.4	8,136	2.141%
12	Secondary		24	2.0	48	0.020%	1.0	24	0.010%	1.0	24	0.010%	3.0	72	0.029%	-	-	0.000%	40.8	979	0.258%
13	**STREET LIGHTING**	4.1	9,842	0.3	2,953	1.241%	1.0	9,842	4.206%	1.0	9,842	4.208%	1.0	9,842	4.015%	-	-	0.000%	-	-	0.000%
14	Total		234,023		238,004	100.0%		234,020	100.0%		233,907	100.0%		245,134	100.0%		225,006	100.0%		380,098	100.0%

NOTES:

Column

A - See Schedule 4.1, Column C.
B - Weighting Factors estimated based on general review of Customer accounting and Customer service activities.
C - Column A times B.
D - Class weighted number of customers divided by the total number of weighted customers for Column C.
E - Equal weighting assigned to all Customers supplied through primary lines.
F - Column A times E.
G - Class weighted number of customers divided by the total number of weighted customers for Column F.
H - Equal weighting assigned to all Customers supplied through secondary lines.
I - Column A times H.
J - Class weighted number of customers divided by the total number of weighted customers for Column I.
K - Equal weighting assigned to all Customers supplied through distribution transformers.
L - Column A times K.
M - Class weighted number of customers divided by the total number of weighted customers for Column L.
N - Based on typical costs to provide Service Drops for customers within each class.
O - Column A times N.
P - Class weighted number of customers divided by the total number of weighted customers for Column O.
Q - Based on typical cost to provide metering for customers within each class.
R - Column A times Q.

S - Class weighted number of customers divided by the total number of weighted customers for Column R.

DEVELOPMENT OF ENERGY ALLOCATORS

Line No.	Class of Service	Rate Code	Load at Meter kWh	Secondary Energy Allocator: Secondary Energy Loss Factor	Secondary Energy Allocator: Load at Secondary Input kWh	Secondary Energy Allocator: Secondary Allocation Factor	Primary Energy Allocator: Load at Primary Output kWh	Primary Energy Allocator: Primary Energy Loss Factor	Primary Energy Allocator: Load at Primary Input kWh	Primary Energy Allocator: Primary Allocation Factor	Transmission Energy Allocator: Load at Transmission Output kWh	Transmission Energy Allocator: Transmission Energy Loss Factor	Transmission Energy Allocator: Load at Transmission Input kWh	Transmission Energy Allocator: Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	802,600,000	0.028109	825,160,283	16.943%	825,160,283	0.022115	843,408,703	15.475%	843,408,703	0.011541	853,142,483	15.429%
2	Domestic All Electric	1.1	2,327,700,000	0.028109	2,393,129,319	49.137%	2,393,129,319	0.022115	2,446,053,374	44.880%	2,446,053,374	0.011541	2,474,283,276	44.747%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	88,800,000	0.028109	91,296,079	1.875%	91,296,079	0.022115	93,315,092	1.712%	93,315,092	0.011541	94,392,041	1.707%
4	(10-100 kW)	2.2	641,800,000	0.028109	659,840,356	13.548%	659,840,356	0.022115	674,432,726	12.374%	674,432,726	0.011541	682,216,354	12.338%
	(110-350 kVA)	2.3												
5	Primary		-	0.028109	-	0.000%	21,385,376	0.022115	21,858,314	0.401%	21,858,314	0.011541	22,110,581	0.400%
6	Secondary		417,430,664	0.028109	429,164,222	8.812%	429,164,222	0.022115	438,655,189	8.048%	438,655,189	0.011541	443,717,708	8.025%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.028109	-	0.000%	-	0.022115	-	0.000%	330,627	0.011541	334,443	0.006%
8	Primary		-	0.028109	-	0.000%	105,543,441	0.022115	107,877,534	1.979%	107,877,534	0.011541	109,122,548	1.973%
9	Secondary		335,690,574	0.028109	345,126,500	7.086%	345,126,500	0.022115	352,758,973	6.472%	352,758,973	0.011541	356,830,164	6.453%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.028109	-	0.000%	-	0.022115	-	0.000%	15,749,226	0.011541	15,930,987	0.288%
11	Primary		-	0.028109	-	0.000%	335,064,542	0.022115	342,474,494	6.284%	342,474,494	0.011541	346,426,992	6.265%
12	Secondary		86,670,672	0.028109	89,106,898	1.830%	89,106,898	0.022115	91,077,497	1.671%	91,077,497	0.011541	92,128,623	1.666%
13	**STREET LIGHTING**	4.1	36,500,000	0.028109	37,525,979	0.770%	37,525,979	0.022115	38,355,866	0.704%	38,355,866	0.011541	38,798,531	0.702%
14	Total		4,737,191,910	0.028109	4,870,349,638	100.00%	5,332,342,996	0.022115	5,450,267,762	100.000%	5,466,347,614	0.011541	5,529,434,732	100.000%

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DEVELOPMENT OF ENERGY ALLOCATORS

NOTES:

A - See Schedule 4.1, Column D.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C and includes customers that are supplied at primary level as shown in Schedule 4.1. Energy Sales increased
- by 1.5% due to reported energy sales been based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Energy Sales increased
- by 1.5% due to reported energy sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Load at Meter kW A	Secondary Demand Allocator: Secondary Demand Loss Factor B	Load at Secondary Input kW C	Secondary Allocation Factor D	Primary Demand Allocator: Load at Primary Output kW E	Primary Demand Loss Factor F	Load at Primary Input kW G	Primary Allocation Factor H	Transmission Demand Allocator: Load at Transmission Output kW I	Transmission Demand Loss Factor J	Load at Transmission Input kW K	Transmission Allocation Factor L
	DOMESTIC													
1	Domestic Regular	1.1	213,072	0.033557	220,222	19.330%	220,222	0.034209	227,756	18.013%	227,756	0.018611	231,995	17.973%
2	Domestic All Electric	1.1	554,737	0.033557	573,353	50.327%	573,353	0.034209	592,966	46.897%	592,966	0.018611	604,002	46.794%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	19,915	0.033557	20,584	1.807%	20,584	0.034209	21,288	1.684%	21,288	0.018611	21,684	1.680%
4	(10-100 kW)	2.2	139,287	0.033557	143,961	12.636%	143,961	0.034209	148,886	11.775%	148,886	0.018611	151,656	11.749%
	(110-350 kVA)	2.3												
5	Primary		-	0.033557	-	0.000%	4,306	0.034209	4,453	0.352%	4,453	0.018611	4,536	0.351%
6	Secondary		84,042	0.033557	86,862	7.624%	86,862	0.034209	89,834	7.105%	89,834	0.018611	91,506	7.089%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.033557	-	0.000%	-	0.034209	-	0.000%	67	0.018611	68	0.005%
8	Primary		-	0.033557	-	0.000%	21,249	0.034209	21,976	1.738%	21,976	0.018611	22,385	1.734%
9	Secondary		67,585	0.033557	69,853	6.131%	69,853	0.034209	72,243	5.714%	72,243	0.018611	73,587	5.701%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.033557	-	0.000%	-	0.034209	-	0.000%	2,716	0.018611	2,766	0.214%
11	Primary		-	0.033557	-	0.000%	57,779	0.034209	59,755	4.726%	59,755	0.018611	60,867	4.716%
12	Secondary		14,945	0.033557	15,447	1.356%	15,447	0.034209	15,975	1.263%	15,975	0.018611	16,273	1.261%
13	**STREET LIGHTING**	4.1	8,681	0.033557	8,972	0.788%	8,972	0.034209	9,279	0.734%	9,279	0.018611	9,451	0.732%
14	Total		1,102,265	0.033557	1,139,254	100.00%	1,222,587	0.034209	1,264,411	100.000%	1,267,193	0.018611	1,290,777	100.000%

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 2008 Class NCP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class NCP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers supplied at transmission level as shown in Schedule 4.1. Class NCP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Load at Meter kW A	Secondary Demand Allocator: Secondary Demand Loss Factor B	Load at Secondary Input kW C	Secondary Allocation Factor D	Primary Demand Allocator: Load at Primary Output kW E	Primary Demand Loss Factor F	Load at Primary Input kW G	Primary Allocation Factor H	Transmission Demand Allocator: Load at Transmission Output kW I	Transmission Demand Loss Factor J	Load at Transmission Input kW K	Transmission Allocation Factor L
	DOMESTIC													
1	Domestic Regular	1.1	176,875	0.033557	182,810	17.162%	182,810	0.034209	189,064	16.067%	189,064	0.018611	192,582	16.034%
2	Domestic All Electric	1.1	567,776	0.033557	586,829	55.092%	586,829	0.034209	606,904	51.577%	606,904	0.018611	618,199	51.469%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	15,548	0.033557	16,069	1.509%	16,069	0.034209	16,619	1.412%	16,619	0.018611	16,928	1.409%
4	(10-100 kW)	2.2	122,722	0.033557	126,840	11.908%	126,840	0.034209	131,179	11.148%	131,179	0.018611	133,620	11.125%
	(110-350 kVA)	2.3												
5	Primary		-	0.033557	-	0.000%	3,569	0.034209	3,691	0.314%	3,691	0.018611	3,760	0.313%
6	Secondary		69,667	0.033557	72,004	6.760%	72,004	0.034209	74,468	6.329%	74,468	0.018611	75,853	6.315%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.033557	-	0.000%	-	0.034209	-	0.000%	55	0.018611	56	0.005%
8	Primary		-	0.033557	-	0.000%	17,615	0.034209	18,217	1.548%	18,217	0.018611	18,556	1.545%
9	Secondary		56,025	0.033557	57,905	5.436%	57,905	0.034209	59,886	5.089%	59,886	0.018611	61,000	5.079%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.033557	-	0.000%	-	0.034209	-	0.000%	2,416	0.018611	2,461	0.205%
11	Primary		-	0.033557	-	0.000%	51,410	0.034209	53,169	4.519%	53,169	0.018611	54,159	4.509%
12	Secondary		13,298	0.033557	13,745	1.290%	13,745	0.034209	14,215	1.208%	14,215	0.018611	14,479	1.205%
13	**STREET LIGHTING**	4.1	8,681	0.033557	8,972	0.842%	8,972	0.034209	9,279	0.789%	9,279	0.018611	9,451	0.787%
14	Total		1,030,590	0.033557	1,065,173	100.00%	1,137,767	0.034209	1,176,689	100.000%	1,179,161	0.018611	1,201,106	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 2008 Class 1CP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

FUNCTIONAL CLASSIFICATION SPLITS

Scenarios

Line No.	Utility Plant Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Substation Demand E	Primary Demand F	Primary Customer G	Distribution Transformers Demand H	Distribution Transformers Customer I	Secondary Demand J	Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N
	PURCHASED POWER														
1	Purchased from Nfld. & Lab. Hydro - Production	100.0%	29.8%	70.2%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	29.8%	70.2%											
	PRODUCTION														
4	Hydro	100.0%	45.6%	54.4%											
5	Other Production	100.0%	100.0%												
	TRANSMISSION														
6	Common	100.0%			100.0%										
	DISTRIBUTION														
7	Substations - Common	100.0%				100.0%									
	Land and Land Use														
8	Primary	100.0%					64.0%	36.0%							
9	Secondary	100.0%									64.0%	36.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					64.0%	36.0%							
12	Secondary	100.0%									64.0%	36.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							73.0%	27.0%					
15	Services	100.0%											100.0%		
16	Meters	100.0%												100.0%	
17	Street Lights	100.0%													100.0%

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Cost Item	Total	Production	Transmission
18	Purchased from Nfld. & Labrador Hydro	100.0%	91.3%	8.7%

Line No.	Cost Item	Total	Common	Specifically Assigned
19	Transmission	100.0%	99.19%	0.81%

Line No.	Cost Item	Total	Hydro Producion	Other Production	Total Production	Transmission Common	Transmission Specifically Assigned	Distribution Substation Common	Distribution Specifically Assigned	Cust. Acc. Cust. Serv.
20	Substations	100.0%	4.99%	0.59%	5.58%	30.23%	0.18%	63.77%	0.24%	0.00%

Line No.	Distribution	Distribution Depreciation, Fixed Assets & CIACs Total	Primary	Secondary	St. Lighting	Distribution Acc. Depreciation Total	Primary	Secondary	St. Lighting
21	Land and Land Use	100.0%	76.64%	19.16%	4.21%	100.0%	76.50%	19.13%	4.37%
22	Conductors, Poles and Fixtures	100.0%	76.64%	19.16%	4.21%	100.0%	76.50%	19.13%	4.37%

Line No.	General Plant Related Costs	Total	Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	5.32%	16.38%	57.63%	20.67%
24	Gen. Prop. Buildings and Structures	100.0%	7.56%	16.67%	57.60%	18.17%
25	Computer Hardware and Software	100.0%	8.59%	8.01%	31.30%	52.10%
26	Gen. Prop. Other Equipment	100.0%	7.43%	19.39%	59.11%	14.06%
27	Transportation	100.0%	4.81%	13.33%	74.90%	6.96%
28	Communication - Total	100.0%	16.05%	16.32%	56.49%	11.14%
29	Communication - Scada	100.0%	13.52%	21.09%	65.40%	0.00%
30	Communication - Total Expenses	100.0%	12.58%	17.14%	54.51%	15.77%
31	Inventory	100.0%	7.70%	34.04%	58.26%	0.00%

FUNCTIONAL CLASSIFICATION SPLITS

Line No.	Utility Plant Category	Reason for Functional Classification
1	Purchased from Nfld. & Lab. Hydro - Production	Classified based on the results ,before deficit allocation. of NLH COS Results for 2007 Forecast Test Year (PU 8 (2007))
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified based on the results ,before deficit allocation, of NLH COS Results for 2007 Forecast Test Year (PU 8 (2007))
3	Purchased from Deer Lake Power - Secondary	Assumed same classification as Nfld. and Lab. Hydro Production related purchased power allocated to NP.
	PRODUCTION	
4	Hydro	Classified based on system load factor from Schedule H. page 105 of 107. of NLH COS for 2007 Forecast Test Year (PU 8 (2007))- Filed in Dec 2006 as Exhibit RDG-1.
5	Other Production	Classified 100% to Demand
	TRANSMISSION	
6	Common	Classified 100% to Demand
	DISTRIBUTION	
7	Substation - Common	Classified 100% to Demand
	Land and Land Use	
8	Primary	Classified between Demand and Customer Based on a minimum system analysis.
9	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
10	Street Lighting	Classified 100% to direct Street Lighting costs.
	Conductors. Poles and Fixtures	
11	Primary	Classified between Demand and Customer Based on a minimum system analysis.
12	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
13	Street Lighting	Classified 100% to direct Street Lighting costs.
14	Transformers	Classified between Demand and Customer Based on a zero intercept method.
15	Services	Classified 100% to Customer
16	Meters	Classified 100% to Customer
17	Street Lights	Classified 100% to Direct Street Lighting.

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Utility Plant Category	Reason for Functional Classification
18	Purchased from Nfld. & Labrador Hydro	Split between production and transmission related purchased power based on results .before deficit allocation. of Nfld. & Lab. Hydro 2007 Cost of Service Study taken from the NLH COS Results for 2007 Forecast (Test Year PU 8 (2007)) - Filed in December 2006 as Exhibit RDG-1.
19	Transmission	Based on an analysis of 2008 year end fixed plant.
20	Substations	Based on an analysis of 2008 year end fixed plant.
	Distribution	
21	Land and Land Use	Split between the different functional groups are based on the split for Conductors Poles and Fittings.
22	Conductors. Poles and Fixtures	Functional split based on a study of fixed assets.
23	Gen. Prop. Land and Land Rights	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
24	Gen. Prop. Buildings and Structures	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
25	Computer Hardware and Software	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
26	Gen. Prop. Other Equipment	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
27	Transportation	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
28	Communication - Total	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
29	Communication - Scada	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
30	Communication - Total Expenses	Based on a 2008 General Property Fixed Plant Allocation Study (2006 Data)
31	Inventory	Based on an allocation of the year end inventory for 2008.

Newfoundland Power Inc.
2008 Cost of Service Study

RECONCILIATION OF EXPENSES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

The total expenses shown on Schedule 1.1, reflects adjustment of the total reported expenses to *include* depreciation and the the amortization of the True-up Deferral and exclude non-regulated expense, Rural Deficit and certain expenses associated recovered through other revenue (expense creadits). Also, Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as oppose oppose to a reduction to class revenue from rates as recorded by the Company.

Total Reported Company Expenses	$386,830	(Return 20)
Add		
Depreciation Expense	$40,649	(Schedule 1.1)
Amortization True-Up Deferral	$3,862	(Schedule 3.2)
Curtailable Credits	$263	(2008 Curtailable Service Option Report)
Less		
Deduct non-regulated expenses[1]	$1,497	
Rural Deficit	$36,325	(Schedule 1.1, page 2 of 2)
Expense Credits		
Wheeling Revenues	$615	(Schedule 1.1)
Joint Use Revenues	$8,861	(Schedule 1.1)
Revenue from Temp. Services and Reconnects	$84	(Schedule 1.1)
Customer Service Fees	$306	(Schedule 1.1)
Total Expense Credits	$9,866	
Rounding	$1	
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	$383,917	

1. Non deductable Expenses (Return 13) + associated tax adjustment - Schedule 5.4

Newfoundland Power Inc.
2008 Cost of Service Study

RECONCILIATION OF REVENUE WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Revenue from Rates shown on Schedule 1.4 does not include customer billings associated with the RSA and MTA rate adjustments. Also the Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as oppose to a reduction to class revenue from rates as recorded by the Company. As a result revenue is increased to remove the impact of the Curtailable Service Option credit payments on revenue.

Revenue from Rates	$497,360	(Return 14)
Add		
RSA Billings	19,252	(Schedule 1.4)
MTA Billings	12,413	(Schedule 1.4)
Curtailable Service Option Credits	$263	(2008 Curtailable Service Option Report)
Total Revenue from Final Rates	$529,288	(Schedule 1.4)

Newfoundland Power Inc.
2008 Cost of Service Study

RECONCILIATION OF RETURN AND TAXES WITH ANNUAL REPORT TO BOARD

(All dollars are times 1,000)

Return and Taxes From Annual Report to Board		
Return on Rate Base (Regulated Earning)	$67,297	(Return 13)
Total Income Tax	19,146	(Return 22)
Total Return and Taxes	86,443	
The Cost of Service Study deducts non-regulated expenses from total expense and the income tax must be adjusted to reflect the increase in taxes that would occur if the non-regulated expenses did not occur.		
Tax Adjustment for non-regulated expenses[1].	501	(Return 13)
Other Adjustments		
Amortization of capital stock issue cost	62	(Return 1, Note 5)
Interest on security deposits	38	(Return 1, Note 5)
Adjusted Return and Taxes (Schedule 1.1)	$87,044	

Notes: 1 - Taxes adjustment associated with non-regulated expenses. This is equal to:

$$\frac{\text{After Tax Adjustment (Return 13)}}{(1 - \text{Tax Rate } (0.335))} \times \text{Tax Rate } (0.335)$$

Demand Management Incentive Account

May 2009

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 BACKGROUND

In Order No. P.U. 44 (2004), the Board approved the creation of a mechanism for Newfoundland Power (the "Company") to mitigate the risk of insufficient recovery of its purchased power expense. The reserve mechanism was intended to lessen the financial risk to the Company resulting from demand and energy forecast variances associated with the implementation of a wholesale demand and energy rate structure by Newfoundland and Labrador Hydro ("Hydro").

In Order No P.U. 35 (2005), the Board approved the definition of the Purchased Power Unit Cost Variance Reserve Account (the "PPUCVR Account") for inclusion in the Company's System of Accounts. The PPUCVR Account defined the mechanics of the reserve mechanism contemplated by Order No. P.U. 44 (2004).

In Order No. P.U. 32 (2007) the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the PPUCVR Account. Since it is more explicitly related to demand management, the DMI Account provides transparency in monitoring purchased power cost variability resulting from variability in peak demand.

In Order No. P.U. 32 (2007), the Board directed Newfoundland Power to provide, with its next general rate application, a report on the operation of the Demand Management Incentive Account, setting out any recommendations for changes if necessary. This report is provided in accordance with the Board's direction.

2.0 OPERATION & IMPACT

In Order No. 32 (2007), the Board approved a definition of the DMI Account to be included in the Company's System of Accounts. The approved definition includes the following parameters:

(i) a range of ±1% of test year wholesale demand costs for which no account transfer is required (the Demand Management Incentive); and

(ii) the use of test year unit demand costs as the basis for comparison against actual unit demand costs in determining the Demand Supply Cost Variance for comparison to the Demand Management Incentive to determine if an account transfer is required.

The DMI Account is charged or credited with the amount by which the Demand Supply Cost Variance exceeds the Demand Management Incentive. The DMI Account, therefore, limits the impacts on the Company of variability in demand supply cost to ±1 percent of test year wholesale demand charges.

The DMI Account provides a meaningful incentive for Newfoundland Power to undertake reasonable initiatives to minimize peak demand. Accordingly, Newfoundland Power takes measures to minimize peak demand requirements of its customers.[1]

Table 1 provides a summary of the reserve calculations for the years 2005 through 2008, with a breakdown of the savings/cost to the Company and customers.

Table 1
Reserve Calculation Summary
($)

	2005	2006	2007	2008
Supply Cost Variance[2]	(438,540)	(2,779,188)	(1,002,611)	(1,170,243)
Company (Savings) Cost	(438,540)	(714,000)	(521,000)	(528,907)
Customer (Savings) Cost	-	(2,065,188)	(481,611)	(641,336)

As Table 1 shows, the operation of the DMI Account and its predecessor, the PPUCVR Account, has resulted in supply cost savings to the benefit of customers and the Company. The Company's efforts to reduce demand through load curtailments and voltage control have contributed to the savings. Since 2005, approximately $3.2 million of the $5.4 million in cumulative savings have been credited to the benefit of customers.

Appendix A provides detailed calculations underlying the information provided in Table 1.

3.0 DISPOSITION OF ACCOUNT BALANCE

In approving the PPUCVR and the DMI Account, the Board retained discretion to determine the disposition of the reserve balance, taking into account the Company's response to the demand and energy rate to reduce system peak. Newfoundland Power is required to file an application with the Board annually, no later than the 1st day of March, for the disposition of any balance in the DMI Account.

The 2006 customer savings were addressed in the 2008 General Rate Application. The Board approved the disposition to customers of the balance resulting from the operation of the DMI Account in 2007 and 2008 through the annual Rate Stabilization Account ("RSA") adjustment.[3]

---

1 Newfoundland Power has a Curtailable Service Option for its customers, which incents customers to reduce demand at the Company's request when peak demand is forecast. In addition, Newfoundland Power has approximately 2.4 MW of curtailable load from its own facilities, and has a limited ability to control system voltages to reduce peak demand. Newfoundland Power's use of any or all of these alternatives is typically coordinated with Hydro's overall control on the Island interconnected grid.

2 For the years 2005 to 2007, the supply cost variance is relative to forecast unit supply cost. For 2008, the supply cost variance is the variance from test year unit demand supply cost. Transfers to reserves are on an after-tax basis. Benefits credited to customers through amortizations (as approved in Order No. P.U. 32 (2007)) or through the RSA (as approved in Order No. P.U. 6 (2008)) are effectively on a before tax basis.

3 Section II(6) of the Rate Stabilization Clause provides for adjustments to the RSA upon order of the Board.

4.0 CONCLUSION

The DMI Account limits the impact on the Company of purchased power cost variances associated with the demand and energy wholesale rate from Hydro, and provides a meaningful demand management incentive for the Company to undertake reasonable initiatives to minimize peak demand.

Since the implementation of the demand and energy wholesale rate, the DMI Account, and its predecessor, the PPUCVR Account, have provided savings to both customers and the Company.

The DMI Account provides better transparency in monitoring supply cost variability resulting from variability in peak demand than the PPUCVR Account it replaced.

The Company does not recommend any changes to the DMI Account.

Computations of Reserve Transfers

2005 to 2008

Table 1-1
2005 Forecast Unit Cost of Purchased Power

1	2005 Forecast Unit Cost[1]	A	5.234¢ per kWh

Table 1-2
2005 Actual Unit Cost of Purchased Power

1	Actual Billing Demand (kW)[2]	A	1,056,055
2			
3	Monthly Demand Charge[3]	B	$4.65 per kW
4			
5	Actual Demand Cost	C =A x B x 12	$58,927,869
6			
7	Energy Purchases (MWh)[4]	D	4,872,666
8			
9	Cost of 1st Block Energy[5]	E= 250,000 MWh x 3.588¢ per kWh x 12	$107,640,000
10	Cost of 2nd Block Energy[6]	F= 1,872,666.0 MWh x 4.7¢ per kWh	$88,015,302
11	Total Energy Costs	G=E+F	$195,655,302
12			
13	Actual Purchased Power Cost	H=G+C	$254, 583,171
14			
15	**2005 Actual Unit Cost**	I=H ÷ D	**5.225¢ per kWh**

[1] As per Order No. P.U. 44 (2004) which included the comparison of Newfoundland Power's forecast unit purchased power cost of 5.234 cents per kilowatt-hour for 2005 to the actual unit cost per kilowatt-hour to determine the variance in purchased power costs to be transferred to or from the reserve.

[2] 2005 Annual Billing Demand from Hydro. As reported in Return 13 of the 2005 Annual Report to the Board.

[3] Monthly demand charge included in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 44 (2004).

[4] As reported in Return 13 of the 2005 Annual Report to the Board.

[5] 1st block energy charge in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 44(2004).

[6] 2nd block energy rate of 4.7¢ per kWh approved in Order No. P.U. 44(2004); 1,872,666.0 MWh = 4,872,666.0 MWh – (250,000 MWh x 12 months).

Table 1-3
2005 Reserve Account Calculation

Forecast Unit Cost (¢ per kWh)[7]	A	5.234
Actual Unit Cost (¢ per kWh)[8]	B	5.225
Purchased Power Unit Cost Variance Factor (¢ per kWh)	C = B - A	(0.009)
Energy Purchases (MWh)[9]	D	4,872,666
Purchased Power Unit Cost Variance	E= D x C	($438,540)
Reserve Deadband[10]	F	±588,000
Amount Outside Deadband	G=E-F	$ -
Less Income Tax	H= G x 35%	$ -
Net Transfer (To) From Reserve	G - H	**$ -**

7 From Table 1-1.
8 From Table 1-2.
9 From Table 1-2.
10 As defined in the PPUCVR Account Definition, approved in Order No. P.U. 35 (2005).

Table 2-1
2006 Forecast Unit Cost of Purchased Power

1	Forecast Billing Demand (kW)[11]	A	1,095,800
2			
3	Monthly Demand Charge[12]	B	$5.64 per kW
4			
5	Forecast Demand Cost	C =A x B x 12	$74,163,744
6			
7	Forecast Energy Purchases (MWh)	D	5,003,600
8			
9	Cost of 1st Block Energy[13]	E= 250,000 MWh x 3.171¢ per kWh x 12	$95,130,000
10	Cost of 2nd Block Energy[14]	F= 2,003,600 MWh x 4.7¢ per kWh	$94,169,200
11	Forecast Energy Cost	G=E+F	$189,299,200
12			
13	Total Forecast Purchased Power Cost	H=G+C	$263,462,944
14			
15	**2006 Forecast Unit Cost**	I=H ÷ D	**5.265¢ per kWh**

[11] 2006 Capital Budget Application Forecast dated March 31, 2005.
[12] Monthly demand charge included in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).
[13] 1st block energy charge in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).
[14] 2nd block energy rate of 4.7¢ per kWh approved in Order No. P.U. 38(2005); 2,003,600 MWh = 5,003,600 MWh – (250,000 MWh x 12 months).

Table 2-2
2006 Actual Unit Cost of Purchased Power

1	Actual Billing Demand (kW)[15]	A	1,044,005
3	Monthly Demand Charge[16]	B	$5.64 per kW
5	Actual Demand Cost	C =A x B x 12	$70,658,258
7	Energy Purchases (MWh)[17]	D	4,875,767.9
9	Cost of 1st Block Energy[18]	E= 250,000 MWh x 3.171¢ per kWh x 12	$95,130,000
10	Cost of 2nd Block Energy[19]	F= 1,875,767.9 MWh x 4.7¢ per kWh	$88,161,091
11	Total Energy Cost	G=E+F	$183,291,091
13	Actual Purchased Power Cost	H=G+C	$253,949,350
15	**2006 Actual Unit Cost**	I=H ÷ D	**5.208¢ per kWh**

[15] 2006 Annual Billing Demand from Hydro. As reported in Return 13 of the 2006 Annual Report to the Board.
[16] Monthly demand charge included in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).
[17] As reported in Return 13 of 2006 Annual Report to the Board.
[18] 1st block energy charge in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).
[19] 2nd block energy rate of 4.7¢ per kWh approved in Order No. P.U. 38(2005); 1,875,767.9 MWh = 4,875,767.9 MWh – (250,000 MWh x 12 months).

Table 2-3
2006 Reserve Account Calculation

Forecast Unit Cost (¢ per kWh)[20]	A	5.265
Actual Unit Cost (¢ per kWh)[21]	B	5.208
Purchased Power Unit Cost Variance Factor (¢ per kWh)	C = B - A	(0.057)
Energy Purchases (MWh)[22]	D	4,875,767.9
Purchased Power Unit Cost Variance	E= D x C	($2,779,188)
Reserve Deadband[23]	F	±714,000
Amount Outside Deadband	G=E-F	($2,065,188)
Less Income Tax	H= G x 35%	($722,816)
Net Transfer (To) From Reserve	G - H	**($1,342,372)**

[20] From Table 2-1.
[21] From Table 2-2.
[22] From Table 2-2.
[23] As defined in the PPUCVR Account Definition, approved in Order No. P.U. 35 (2005).

Table 3-1
2007 Forecast Unit Cost of Purchased Power

1	Forecast Billing Demand (kW)[24]	A	1,078,050
2			
3	Monthly Demand Charge[25]	B	\$5.64 per kW
4			
5	Forecast Demand Cost	C =A x B x 12	\$72,962,424
6			
7	Forecast Energy Purchases (MWh)	D	4,964,000
8			
9	Cost of 1st Block Energy[26]	E= 250,000 MWh x 3.171¢ per kWh x 12	\$95,130,000
10	Cost of 2nd Block Energy[27]	F= 1,964,000 MWh x 4.7¢ per kWh	\$92,308,000
11	Forecast Energy Cost	G=E+F	\$187,438,000
12			
13	Total Forecast Purchased Power Cost	H=G+C	\$260,400,424
14			
15	**2007 Forecast Unit Cost**	I=H ÷ D	**5.246¢ per kWh**

24 2007 Capital Budget Application Forecast dated April 21, 2006.

25 In Order No. P.U. 42(2006), the Board approved revised customer rates for Newfoundland Power, effective January 1,2007, reflecting, among other things, additional purchased power costs forecast to be incurred by Newfoundland Power in 2007 as a result of the 2007 wholesale rate change, together with a year-end adjustment to Newfoundland Power's Rate Stabilization Clause to true up any under-recovery or over-recovery of increased 2007 purchased power costs resulting from the January 1, 2007 change in customer rates. To avoid recovering a portion of 2007 purchased power costs twice, the forecast unit cost of purchased power and the normalized actual unit cost of purchased power used in the computation of the Purchased Power Unit Cost Variance Factor were based on the wholesale purchased power rate approved in Order No. P.U. 38(2005), which was the rate in effect prior to the wholesale rate change effective January 1, 2007.

26 1st block energy charge in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).

27 2nd block energy rate of 4.7¢ per kWh approved in Order No. P.U. 38(2005); 1,964,000 MWh = 4,964,000 MWh – (250,000 MWh x 12 months).

Table 3-2
2007 Actual Unit Cost of Purchased Power

Adjusted Actual Billing Demand (kW)[28]	A	1,067,270
Monthly Demand Charge[29]	B	\$5.64 per kW
Actual Demand Cost	C =A x B x 12	<u>\$72,232,834</u>
Energy Purchases (MWh)[30]	D	5,013,056
Cost of 1st Block Energy [31]	E= 250,000 MWh x 3.171¢ per kWh x 12	\$95,130,000
Cost of 2nd Block Energy [32]	F= 2,013,056 MWh x 4.7¢ per kWh	<u>\$94,613,632</u>
Total Energy Cost	G=E+F	<u>\$189,743,632</u>
Actual Purchased Power Cost	H=G+C	<u>\$261,976,466</u>
2007 Actual Unit Cost	I=H ÷ D	**5.226¢ per kWh**

[28] Actual 2007 billing demand adjusted to reflect the generation credit approved as part of the 2006 wholesale rate approved in Order No. P.U. 38(2005). A reduction of 7,444 kW was made to the actual billing demand of 1,074,714 kW. The reduction was calculated as the difference between the 2006 generation credit and the 2007 generation credit, times 0.99 [(125,450 kW – 117,930 kW) × 0.99 = 7,444 kW] to reflect that the 2007 billing demand was based on the minimum billing demand.

[29] Monthly demand charge included in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005). See footnote 25.

[30] As reported in Return 13 of 2007 Annual Report to the Board.

[31] 1st block energy charge in Newfoundland Hydro's wholesale rate approved in Order No. P.U. 38 (2005).

[32] 2nd block energy rate of 4.7¢ per kWh approved in Order No. P.U. 38(2005); 2,013,056 MWh = 5,013,056 MWh – (250,000 MWh x 12 months).

Table 3-3
2007 Reserve Account Calculation

Forecast Unit Cost[33] (¢ per kWh)	A	5.246
Actual Unit Cost[34] (¢ per kWh)	B	5.226
Purchased Power Unit Cost Variance Factor (¢ per kWh)	C = B – A	(0.020)
Energy Purchases (MWh)[35]	D	5,013,056
Purchased Power Unit Cost Variance	E= D x C	($1,002,611)
Reserve Deadband[36]	F	±$521,000
Amount Outside Deadband	G=E-F	($481,611)
Less Income Tax	H= G x 36.12%	($173,958)
Net Transfer (To) From Reserve	G - H	**($307,653)**

[33] From Table 3-1.
[34] From Table 3-2.
[35] From Table 3-2.
[36] As defined in the PPUCVR Account Definition, approved in Order No. P.U. 35 (2005).

Table 4-1
2008 Test Year Unit Cost of Demand Supply

1	Test Year Billing Demand (kW)[37]	A	1,101,890
2	Monthly Demand Charge[38]	B	$4.00 per kW
3	Test Year Demand Costs	C = A x B x 12	$52,890,720
4	Test Year Energy Purchases (MWh)[39]	D	5,099,900
5	**Test Year Unit Cost**	C ÷ D	**1.037¢ per kWh**

Table 4-2
2008 Actual Unit Cost of Demand Supply

1	Actual Billing Demand (kW)[40]	A	1,074,714
2	Monthly Demand Charge	B	$4.00 per kW
3	Actual Demand Cost	C = A x B x 12	$51,586,272
4	Actual Energy Purchases (MWh)[41]	D	5,088,014
5	**Actual Unit Cost**	C ÷ D	**1.014¢ per kWh**

37 The 1,101,890 kW represents the forecast 2007-2008 winter season native peak less the generation credit (source: line 13 of Appendix C to the Customer, Energy and Demand Forecast 2007-2008 (l[st] Revision) provided to the Board with the Amended Application on October 11. 2007).

38 The wholesale demand rate effective January 1, 2007, approved in Order No. P.U. 8 (2007).

39 The 5,099,900 kWh represents the 2008 test year forecast purchases (source: line 14 of Appendix C to the Customer, Energy and Demand Forecast 2007-2008 (l[st] Revision) provided to the Board with the Amended Application on October 11. 2007).

40 The 1,074,714 kW is the Minimum Billing Demand, as reported in Return 15 of the 2008 Annual Report to the Board, established based on Newfoundland Hydro's 2007 Test Year. Source: Letter from Newfoundland Hydro to Newfoundland Power and copied the Board dated April 4, 2008.

41 Source: Return 15 of the 2008 Annual Report to the Board.

Table 4-3
2008 Demand Supply Cost Variance

1	Actual Unit Cost (¢ per kWh)[42]	A	1.014
2	Test Year Unit Cost (¢ per kWh)[43]	B	1.037
3	Energy Purchases (MWh)	C	5,088,014
4	**Demand Supply Cost Variance**	(A - B) x C	**($1,170,243)**

Table 4-4
2008 DMI Account Calculation

1	Demand Supply Cost Variance[44]	A	($1,170,243)
2	Demand Management Incentive[45]	B	±$528,907
3	Amount Exceeding Demand Management Incentive	C = (A - B)	($641,336)
4	Less Income Tax	D = C x 33.5%	($214,848)
5	**Net Transfer (To) From DMI Account**	C - D	**($426,488)**

[42] From Table 4-2.
[43] From Table 4-1.
[44] From Table 4-3.
[45] Test year demand cost from Table 4-1 of $52,890,720 times ±1%.

Energy Supply Cost Variance

May 2009

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1.0 BACKGROUND

Load requirements on the system increase annually, principally as a result of the addition of new customers. Changes in Newfoundland & Labrador Hydro's ("Hydro") wholesale rate in 2007 resulted in a dramatic increase in the cost to Newfoundland Power to supply increases in customer load.[1] The increase was the result of higher fuel costs related to production at Holyrood, which is reflected in Hydro's wholesale 2nd block energy charge.

The current wholesale energy cost dynamics are such that the cost to Newfoundland Power of additional energy purchases ("Marginal Energy Supply Cost") is greater than the average energy supply cost reflected in customer rates ("the Average Energy Supply Cost").

To ensure reasonable recovery by Newfoundland Power of prudently incurred energy supply costs, the Board, in Order No. P.U. 32 (2007), approved a change to the Rate Stabilization Clause to provide for the recovery of the difference between the Marginal Energy Supply Cost and the Average Energy Supply Cost (the "Energy Supply Cost Variance") for the period 2008 to 2010.

This report is provided to assist the Board in their review of the operation and impact of the recovery mechanism.[2]

2.0 OPERATION & IMPACT

The Rate Stabilization Clause provides that, for the years 2008 to 2010, the Rate Stabilization Account (RSA) shall be increased or reduced by the Energy Supply Cost Variance.

Table 1 provides the computation of the Energy Supply Cost Variance on a ¢ per kWh basis.

Table 1
Energy Supply Cost Variance
¢ per kWh

Difference in energy costs	
Average Test Year Energy Supply Cost[3]	5.535 ¢/kWh (A)
Wholesale rate 2nd Block price[4]	8.805 ¢/kWh (B)
Energy Supply Cost Variance	3.270 ¢/kWh (C = B – A)

1 The 2nd block of the wholesale rate increased from 4.70 ¢ per kWh to 8.805 ¢ per kWh.
2 In Order No. P.U. 32 (2007), the Board indicated it would review the operation and impact of the Energy Supply Cost Variance in the Rate Stabilization Account as part of the Company's next general rate application.
3 The average test year cost of energy was determined by applying the wholesale energy rate effective January 1, 2007 to the 2008 test year forecast energy purchases.
4 Hydro's wholesale rate approved in Order No. P.U. 8 (2007).

Table 2 shows the 2008 year-end transfer to the RSA, based on the difference in energy purchases from the 2008 test year forecast.

Table 2
2008 Energy Supply Cost Variance

Difference in energy purchases from test year		
Weather Normalized Annual Purchases	5,088,014,000	kWh (A)
Test Year Annual Purchases	5,099,900,000	kWh (B)
Difference	(11,886,000)	kWh (C = A – B)
Transfer (to) from reserve ((C x 3.270 ¢ per kWh)/100)	($388,672)	

The 2008 year-end transfer to the RSA was $388,672. In 2008, Newfoundland Power's energy purchases from Hydro were lower than the 2008 test year forecast. Therefore, this transfer represents a benefit to customers that is provided by means of the annual RSA rate adjustment for the period July 1, 2009 to June 30, 2010.

Table 3 shows the 2009 Energy Supply Cost Variance that is forecast to be recovered by Newfoundland Power through the RSA over the period July 1, 2010 to June 30, 2011.

Table 3
2009 Forecast Energy Supply Cost Variance

Difference in energy purchases from test year		
Weather Normalized Annual Purchases	5,192,600,000	kWh (A)
Test Year Annual Purchases	5,099,900,000	kWh (B)
Difference	92,700,000	kWh (C = A – B)
Transfer (to) from reserve ((C x 3.270 ¢ per kWh)/100)	$3,031,290	

Without the RSA provision enabling recovery of the Energy Supply Cost Variance, Newfoundland Power would incur a forecast 2009 shortfall in recovery of energy supply costs of $3,031,290. This forecast recovery shortfall is due to the difference between the Marginal Energy Supply Cost and the Average Energy Supply Cost.

In accordance with Newfoundland Power's proposals in the 2010 General Rate Application, forecast 2010 wholesale supply costs will be rebalanced with customer rates. Accordingly, no Energy Supply Cost Variance is forecast for year-end 2010. Increased 2010 supply costs arising from current Marginal Supply Cost dynamics are forecast to be $6.1 million.[5]

3.0 CONCLUSION

Due to the difference between the Marginal Energy Supply Cost and the Average Energy Supply Cost, even modest increases in customer load requirements can result in a shortfall in recovery of prudently incurred energy supply costs. This systemic shortfall can be expected to continue as long as load growth continues and the Marginal Energy Supply Cost remains higher than the Average Energy Supply Cost.

Consequently, there continues to be a requirement for the provision for the recovery of the Energy Supply Cost Variance through the RSA.

The Energy Supply Cost Variance mechanism provides for the reasonable recovery by Newfoundland Power of prudently incurred energy supply costs.

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5 Table 4 shows the 2010 energy supply cost forecast to be transferred for recovery through the RSA over the period July 1, 2011 to June 30, 2012 in the absence of a general rate application in 2010.

Table 4
2010 Energy Supply Cost Variance

Difference in energy purchases from test year		
Weather Normalized Annual Purchases	5,287,300,000	kWh (A)
Test Year Annual Purchases	5,099,900,000	kWh (B)
Difference	187,400,000	kWh (C = A – B)
Transfer (to) from reserve	$6,127,980	
((C x 3.270 ¢ per kWh)/100)		

Opinion

on

Capital Structure and Fair Return on Equity

Prepared for

NEWFOUNDLAND POWER

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

May 2009

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I. INTRODUCTION AND EXECUTIVE SUMMARY

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies, in more than 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix G.

I have been asked by Newfoundland Power (NP) to: (1) assess the reasonableness of the Company's proposed capital structure; and (2) recommend an allowed return on equity (ROE) for NP.

B. EXECUTIVE SUMMARY

My conclusions are as follows:

1. The automatic adjustment formula is clearly not producing returns that meet the fair return standard. The fair return for setting the allowed return on equity needs to be recalibrated.

2. The sensitivity of the cost of equity to government bond yields is materially lower than the existing automatic adjustment mechanism implies. In addition, the cost of equity moves in the same direction as the utility cost of debt; this relationship has not been reflected in the automatic adjustment mechanism. As a result, the allowed ROEs have decreased over time to a much greater extent than is justified and recently have moved in the wrong direction. The application of the formula in current circumstances would produce a lower ROE at the same time that the utility debt costs and required credit premiums have increased, an outcome which is illogical.

3. The allowed return for NP must meet all three criteria of the fair return standard, including the comparable return standard. The fair return extends to both the capital structure and return on equity, that is, the overall return allowed must satisfy the fair return standard.

4. Satisfying the comparable return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, the small number of Canadian utilities with equity market data and the obvious circularity of comparisons limited to utilities that are all subject to similar ROE automatic adjustment mechanisms.

5. NP's forecast capital structure includes a common equity ratio of 45%. The Company's capital structure is reasonable in light of its business risks, the importance of maintaining or improving the existing credit ratings, and the capital structures and credit metrics of NP's peers, with whom NP competes for capital and whose total returns form a basis for satisfying the comparable returns standard.

6. The fair return on equity for NP was estimated at 11.0%. The fair return for NP reflects the following:

   a. The return on equity is based on the results of three tests, equity risk premium, discounted cash flow and comparable earnings.

   b. The equity risk premium test results are based on three separate approaches. The equity risk premium tests indicate the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	8.75%
DCF-Based	10.00%
Historic Utility	10.50%
Average	9.75%

   c. The discounted cash flow test, applied to a sample of benchmark low risk U.S. electric and gas utilities, supports a cost of equity of 10.5-11.0% (midpoint of 10.75%).

   d. The allowance for financing flexibility should be, at a minimum, 0.5%. The addition of a 0.5% financing flexibility adjustment results in a cost of equity based on the market-based equity risk premium and DCF tests of approximately 10.25-11.25%.

e. The comparable earnings test shows that, based on the achievable earnings returns of low risk unregulated Canadian firms, whose reasonableness was corroborated by the returns in unregulated U.S. firms, a fair return applicable to a benchmark utility would be approximately 11.5-11.75%.

f. With primary weight given to the capital market-based tests, equity risk premium and discounted cash flow, the fair return on equity for NP is estimated at 11.0%.

II. TIME FOR A NEW BENCHMARK ROE

For more than 10 years, the allowed ROE for the Newfoundland Power has been subject to an automatic adjustment formula. The defining element of the formula is its reliance on long-term Canada bond yields to determine the allowed ROE. The automatic adjustment formula changes the allowed ROE by 80% of the change in actual long-term Canada bond yields from one year to the next. If the formula had been applied using the long-term government of Canada bond yield of 3.75% prevailing in mid-April 2009, the allowed ROE for Newfoundland Power would be only 8.3%, only 1.7 percentage points above the Company's cost of new long-term debt.

Since the inception of the formula in Canada in the mid-1990s, the allowed ROEs for utilities in Canada have tracked the downward trend in long-term Canada bond yields. Although the formulas have been reviewed by regulators (twice by the PUB since the formula was originally adopted for NP in 1998), the overriding factor determining the allowed ROE has been the downward trend in long-term Canada bond yields, rather than factors which directly drive equity return requirements.

Since the formulas were first introduced in 1994/1995, the long-term Canada bond yield has fallen by approximately 550 basis points from 9.25% to 3.75%. If the formulas were applied at current long-term Canada bond yields, the corresponding reduction in allowed ROEs for Canadian utilities would be approximately 425 to 450 basis points, that is, approximately 75%-80% of the decline in long-term Canada bond yields.

With the widespread adoption of similar automatic adjustment formulas, allowed ROEs in Canada have converged to a relatively narrow range. Moreover, with virtually all major Canadian utilities subject to a similar formula, comparisons among the ROEs as a "reasonableness check" are subject to an extensive degree of circularity which makes those comparisons of very limited value.

The decline in long-term Canada bond yields experienced during the past 15 years reflects in large part a sea change in the Canadian economy characterized by a shift from huge government deficits and indebtedness to an unbroken string of government surpluses (commencing in 1997) and a steady reduction in the relative (to the size of the economy) amount of debt outstanding.[1] With the vast improvement in the government's finances and the reduction in government debt outstanding relative to the size of the economy came the decline in long-term Canada bond yields. The secular decline in long-term Canada bond yields reflects three factors: a reduction in the expected rate of inflation over the longer-term, the waning of investors' fear that inflation would reignite to levels experienced in the 1980s decade, and a declining supply of long-term government debt relative to demand.

Of these three factors, only the decline in the expected rate of inflation over the longer-term would directly translate into a corresponding decline in the cost of equity. The fear that inflation would reignite had taken the form of a premium that investors required to "lock in" investment in long-term bonds with fixed coupon rates. Investors in equities, in contrast, are not similarly locked in and thus equity investors did not demand the same "lock in" premium. In contrast to the fixed rates on debt, corporate earnings, which ultimately determine the returns to equity investors, are better able to keep pace with the rate of inflation. The elimination of the "lock in" premium as inflationary fears waned lowered the risk associated with investment in long-term government bond yields. In the absence of a commensurate decline in the cost of equity, the result was an increase in the market equity risk premium.

With respect to the third factor, strong demand for long-term government debt by institutions, particularly those seeking to match the duration of their assets and liabilities, creates an imbalance in the supply of and demand for long-term government securities. The scarcity factor, in turn, leads to abnormally low long-term government bond yields. The reduction in long-term government bond yields arising from a demand/supply imbalance has no bearing on the cost of equity.

[1] The Federal government is anticipating budget deficits for fiscal years 2009/10 to 2012/13.

Layered over the secular decline in long-term Canada bond yields have been periodic "flights to quality" throughout the period the formulas have been in effect. A "flight to quality" occurs when investors flee from risky securities to the safe haven of the safest securities, long-term government securities. A "flight to quality" puts downward pressure on the yields of default-free securities, e.g. long-term government bond yields, and a corresponding increase in the cost of risky forms of capital.

Since the introduction of automatic adjustment formulas, the capital markets have been characterized by multiple crises of varying proportions, including the "Asian Contagion" and ensuing Russian sovereign debt default in 1997-1998, the dot.com bust in 2000, the Enron bankruptcy in 2001, 9/11, the run-up to and the outbreak of the Iraq War in March 2003, and the global financial crisis dating from August 2007. The series of market crises and flights to quality during the period the formulas have been in operation has kept downward pressure on the level of long-term Canada bond yields, which in turn has suppressed the level of allowed ROEs.[2]

As a result of reliance on a formula which has been governed solely by changes in the long-term Canada bond yield, rather than the composite of factors that bear on equity return requirements, the allowed ROEs have fallen below levels commensurate with a fair return. The extent to which the formula ROEs have diverged off course from a fair and reasonable level over time can be assessed by a comparison of the allowed ROEs of Canadian and U.S. utilities.

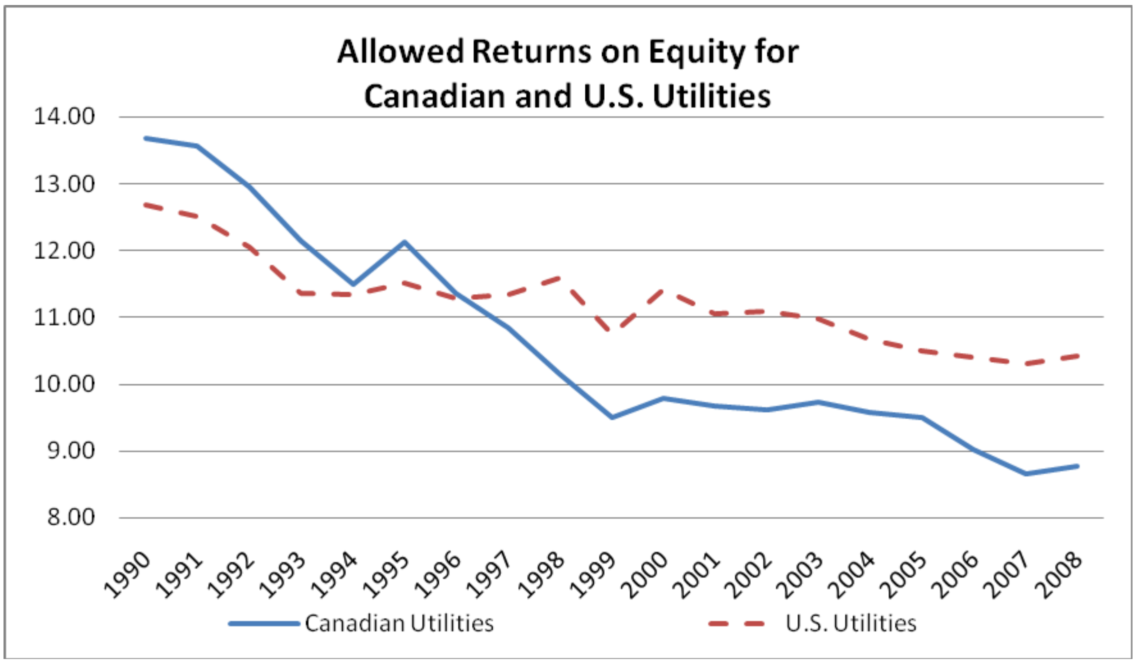
This comparison is germane given (1) the significant integration of the Canadian and U.S. capital markets, (2) the similarity in the business (or operating environments) for distribution

[2] To put this in some perspective, Consensus Economics, *Consensus Forecasts* estimates the long-run average yield on 10-year Canada bonds twice annually, in April and October. Since 1997, the forecast yield in October for the subsequent 11 year period has averaged 5.5%. By comparison, the actual yields on 10-year Canada bonds during 1998 to 2008 have averaged 4.8%, or approximately 0.7 percentage points lower than the long-term forecast yield.

utilities in Canada and the U.S., and (3) the similarity in the regulatory models in the two countries.

Figure 1 below compares the allowed ROEs in Canada and the U.S. since 1990.

Figure 1



Source: Schedule 22

Figure 1 shows that allowed returns in the U.S. and Canada were comparable until automatic adjustment formulas tied to government bond yields became the norm (approximately 1997-1998) in Canada. With the widespread adoption of automatic adjustment formulas in Canada, a significant gap between the allowed ROEs in the two countries emerged, a gap which has persisted through 2008. Between 1998 and 2008, Canadian utilities' allowed ROEs have averaged close to 1.4 percentage points lower than those of their U.S. peers, whose allowed ROEs continue to be set using various tests and informed judgment. The average yield on long-term government bonds in the two countries over the same period differed by less than 0.1% (10 basis points).

In 2008, the differential between the average allowed ROE for Canadian utilities (8.8%) and the average ROE adopted for U.S. electric and gas utilities (10.4%) was 1.6 percentage points despite a differential between long-term government bond yields in the two countries of less than 0.2%.

Since allowed ROEs in the U.S. are determined using various cost of equity tests, they can be used, retrospectively, to test the sensitivity of the utility cost of equity to changes in long-term government bond yields. When the quarterly allowed ROEs from 1994 (the year the formula was first introduced in Canada) to 2008 are regressed against long-term Treasury bond yields and utility/Treasury bond yield spreads lagged by six months[3], the result indicates that the allowed ROEs changed by approximately 55 basis points for every one percentage point change in long-term government bond yields and was positively related to the utility/government bond yield spread. By comparison, the automatic adjustment formula relied upon in Newfoundland and Labrador assumes that the ROE changes by 80 basis points for every one percentage point change in long-term government bond yields and includes no other explanatory variables. The analysis strongly indicates that, with the benefit of hindsight, the cost of equity is significantly less sensitive to changes in long-term government bond yields than the automatic adjustment formulas assume.

The evidence that the formulas have not been producing returns that meet the fair return standard has been mounting for some time.

As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows

[3] To take account of the fact that the date of the decision lags the period covered by the market data on which the ROE decision was based. Excluding the spread as a second explanatory variable, the regression indicates that the allowed ROEs changed by approximately 40 basis points for every one percentage point change in long-term government bond yields.

> the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

In its June 2006 *Canadian Hydrocarbon Transportation System* report, the National Energy Board (NEB) reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they had "Buy" recommendations on utility stocks, the recommendations tended to reflect the prospects of the unregulated operations. Analysts also commented that companies had reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views.[4] Some market participants expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated that,

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

[4] The NEB did not consult with analysts for the purpose of their 2008 report, in light of its then ongoing cost of capital proceeding for TransQuébec and Maritimes Pipeline.

In *Pipelines/Gas & Electric Utilities,* dated December 7, 2006, Karen Taylor, then equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB, BCUC and OEB formulas[5]] are confiscatory and likely violate the Fair Return Standard."[6]

With the application of the formulas for 2009, the resulting allowed ROEs were not only too low to be fair to investors, they had clearly moved in the wrong direction. While flight to quality had pushed the actual yields and forecast yields on long-term government bonds lower during 2008, other indicators were signalling a higher cost of capital. Between November 2007 and November 2008 (when the formula ROEs are typically calculated), the yield on long-term A rated utility bonds had jumped 180 basis points, from approximately 5.7% to 7.5%. Over the same period, the yield on the TSX Composite had also risen by more than 1.5 percentage points as the equity market plunged. The higher dividend yield, similar to the increase in corporate debt yields, points to a higher cost of capital. Yet the application of the formula, tied solely to government bond yields resulted in a lower allowed ROEs on average in 2009 than in 2008.

Were the regulators to set the allowed ROEs at prevailing long-term Canada bond yields, they would be lower still. Yet the cost of debt for these same utilities remains more than a full percentage point above the yields prevailing when the ROEs were set in late 2007. It makes no logical sense that equity investors, who are subordinate to debt investors in terms of their claims on the assets of the utility, would demand a lower return when debt investors are demanding a higher return. The divergence between the observed trends in the cost of utility long-term debt and the automatic adjustment formula ROE result provides a strong signal that the automatic adjustment formulas are not working properly.

[5] Alberta Energy and Utilities Board (EUB), British Columbia Utilities Commission (BCUC) and Ontario Energy Board (OEB).

[6] Studies commissioned by the Canadian Gas Association and the Canadian Energy Pipeline Association published in 2008 also came to the conclusion that the ROEs produced by the automatic adjustment formulas did not meet the fair return standard.

As a further perspective, an allowed ROE for NP of 8.3% would represent a significant narrowing of the premium between the allowed ROE and the coincident cost of new 30-year debt. An allowed ROE of 8.3%, as noted above, would equate to a premium of only 1.7 percentage points above the prevailing cost of new long-term debt. By comparison, when the PUB reviewed the formula in 2003 and in 2007, the allowed ROEs were approximately 3.25 and 3.0 percentage points respectively higher than the corresponding cost of long-term Canadian A-rated utility debt. There is no logical reason that the differential between the returns required by investors to invest in the common equity of utilities like NP rather than the Company's long-term debt would have declined between 2003 and 2009 as the operation of the automatic adjustment formula implies. The material narrowing of the spread between the cost of new utility long-term debt and the automatic adjustment formula ROE result provides further support for the conclusion that the automatic adjustment formulas are not producing reasonable results.

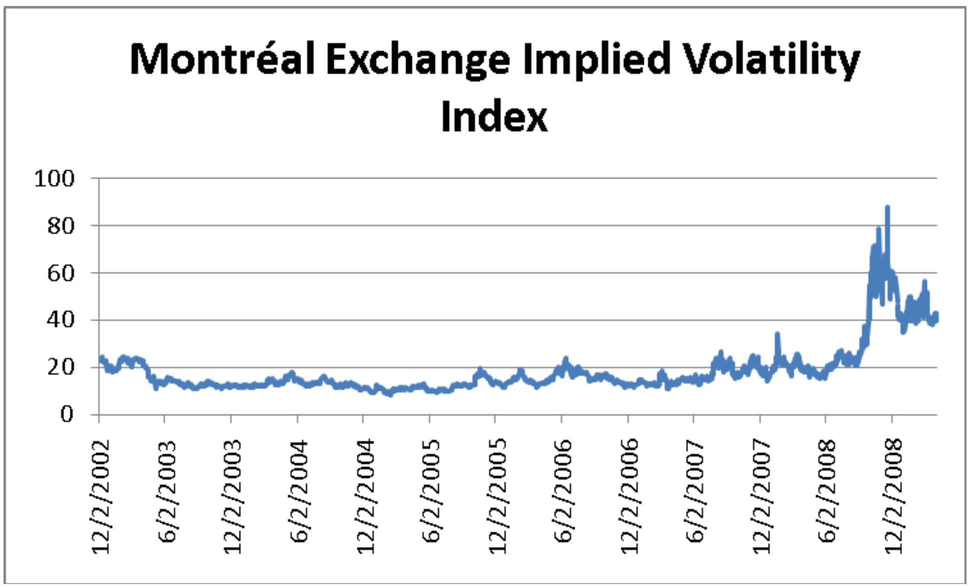
In March 2006, the yield on the TSX Composite Index was 2.3%; at the end of March 2009 it was 4.2%. It makes no logical sense that utility equity investors would demand a lower return when the virtual doubling of the market dividend yield (reflecting a 30% price decline) is signalling an increase in the cost of equity. The divergence between the observed trends in the market cost of and the automatic adjustment formula ROE result is provides an additional strong signal that the automatic adjustment formula is not working properly.

In addition to the increase in the market dividend yield, the increase in the cost of equity, and the widening of the equity risk premium, is reflected in the significant increase in the volatility in the equity markets, as represented by Implied Volatility Index ("MVX") introduced by the Montréal Exchange in 2002. The Montréal Exchange states that the "MVX is a good proxy of investor sentiment for the Canadian equity market: the higher the Index, the higher the risk of market turmoil. A rising Index therefore reflects the heightened fears of investors for the coming month."[7] In other words a rising MVX is an indicator of rising investor risk aversion and a rising market risk premium.

[7] www.m-x.ca/indicesmx_mvx_en.php

As shown in Figure 2 below, during much of 2002-2007, prior to the onset of the financial crisis, the MVX was relatively stable, trading within a range of 8 to 24, and averaging 15. During 2008, the MVX rose sharply, peaking at almost 90 in November 2008, its highest level since inception, and averaging close to 60 during the 4^{th} quarter. While volatility has declined, the MVX has continued to trade substantially above its 2002-2007 levels, averaging over 40 in the first quarter of 2009. To put this in perspective, the MVX never exceeded 25 prior to August 2007. Since mid-2008, the MVX has signaled higher risk aversion and, therefore, an increase in the equity risk premium.[8]

Figure 2



Source: Montréal Exchange

[8] Similarly, in the U.S. the VIX index, an equity volatility index introduced in 1993 by the Chicago Board Options Exchange (often referred to as the "Fear Gauge"), is an indicator of investor risk aversion. The index indicates that, during much of 2004-2006, the equity market was perceived as unusually stable; trading within a range of 10 to 19, and averaging 13.5. The VIX index rose steadily throughout much of 2007, averaging 100% higher during the 4^{th} quarter than during the 4^{th} quarter of 2006. During the fourth quarter of 2008, as the depth of the financial crisis was revealed, the index jumped sharply, peaking at almost 80 in October 2008, its highest level since inception, and averaging close to 60 during the entire 4^{th} quarter. At the end of March 2009, it was trading around 45, levels not experienced previously. On only six days prior to the current financial market crisis, four during the 1998 global market crisis and two times in 2001-2002 in the wake of the recession in the U.S., has the index traded at or above 40. However, at no time prior to this financial crisis has it touched 45.

The unambiguous divergence between the trends in long-term government bond yields on the one hand and utility bond yields and the market cost of equity on the other has led other equity analysts to reach the conclusion that the formula is broken. In RBC Capital Markets' January 16, 2009 *Industry Comment* entitled "Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?", analyst Robert Kwan commented,

> With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).

Mr. Kwan recommended from a risk/reward perspective

> "We would focus on companies with the least exposure to the formula."

A February 23, 2009 report by Macquarie Research entitled *ROE Formula May Finally Bite the Dust* concluded that government bond yields bear little resemblance to any private company's cost of capital. The report also concluded that

> Lack of comparability between allowed utility ROEs and returns on similar investments is driving the emerging capital access problem. In support of the argument the comparability criterion is not being met, utility customers and their expert witnesses like to point out that allowed returns for U.S. utilities are considerably higher than allowed returns in Canada. No matter how we slice the data, we concur with this opinion.

On March 19, 2009 the National Energy Board released its cost of capital decision for TransQuébec and Maritimes Pipeline (TQM). In that decision, the NEB expressed the view that

> …. there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of

> financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

The NEB also noted that

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

The NEB's decision for TQM replaced the automatic adjustment formula ROE and deemed capital structure with an after-tax weighted average cost of capital (ATWACC) of 6.4%. Although the decision specified neither a capital structure nor allowed ROE, it provided some alternative combinations of common equity ratio and ROE equivalent to the 6.4% ATWACC so as to facilitate comparisons. The 2007/2008 ROE at the TQM and Intervenor recommended equity ratios of 40% and 32% would be 9.7% and 11.2%, respectively.[9] At the same common equity ratio last approved for TQM of 30%, the return adopted by the NEB for TQM is more than 250 basis points higher than the corresponding 2007 and 2008 ROEs of 8.46% and 8.72% if determined by the NEB's multi-pipeline formula. In coming to its decision, the NEB concluded that market returns of U.S. companies were relevant to the cost of capital of Canadian firms, as U.S. market returns can be a useful proxy for investment opportunities in the increasingly integrated global capital markets. Following its decision for TQM specifically, the NEB has decided to consider whether it should initiate a full review of its RH-2-94 decision which adopted the automatic adjustment formula.[10]

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[9] TQM's last approved deemed common equity ratio was 30%.

[10] The potential NEB review is part of a broader movement to address the failings of the existing automatic adjustment formulas. The Alberta Utilities Commission is in the process of reviewing the automatic adjustment formula, the Ontario Energy Board has initiated a more limited review of the reasonableness of the 2009 values produced by its formulaic approach to setting the cost of capital for electricity distributors, and Gaz Metro is applying to the Régie for a change in cost of capital methodology.

BMO Capital Markets analyst George Lazarevski in *Pipelines and Utilities* (March 30, 2009) stated,

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.

On April 24, 2009, Scotia Capital commented,

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.
>
> Beginning with the National Energy Board in early 1995, Canadian energy regulators have largely adopted formula-based annual adjustments to utilities' allowed return on equity. These formula have been based on the capital asset pricing model. A base "riskfree" rate, represented by long Canada bond yields, is augmented by an equity risk premium, chosen to represent the business and financial risk of the utilities. The NEB's formula was created in 1994 and 1995, when Canada long bond yields reached over 9% at times, due to a range of factors, including ratings downgrades, large public sector deficits, and bearish domestic and international market sentiment towards Canadian government debt.
>
> As Canada's public sector reformed its finances, long Canada yields have come down, gradually but steadily, since early 1995. This led to a gradual decline in utility allowed ROEs, which has been a challenge for equity holders, and a challenge for utility management to offset by trying to "over-earn" the regulatory target, which is used to set rates.
>
> The onset of economic and financial market turmoil in late 2007 led to a further, more rapid decline in Canada yields, mimicking the global flight to the safety of top-quality sovereign debt, and reflecting widespread investor aversion to risk of all kinds. This triggered a decrease in Canadian utility regulators' formula-driven ROEs, to unprecedented low levels. However, utility bond spreads, and their cost of equity capital, were rising.
>
> Very recently, the NEB recognized these adverse and undesirable results, in what we view as a very significant Decision in the case of Trans Québec & Maritimes Pipeline. The NEB varied from its formula, which it had applied virtually universally to utilities in its jurisdiction since 1995. The ROE relief was material, lifting TQM's ROE from the formula-set 8.46% and 8.71% in 2007 and 2008 (on the NEB's

deemed equity capitalization of 30%) to roughly 11.6% to 11.8%, based on the same capital structure and the embedded cost of debt.[11]

With this backdrop, it is apparent that a review from first principles of the cost of capital (capital structure and ROE) for NP is warranted and the allowed return rebased at a level which satisfies the fair return standard.

[11] Stephen Dafoe, "Falling Canada Yields and Utility ROEs", *Capital Points*, ScotiaBank Group, April 24, 2009.

III. THE FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[12] which are echoed in numerous regulatory decisions across North America, including the PUB's June 20, 2003 Decision and Order of the Board, Order No. P.U. 19 (2003) for Newfoundland Power. The PUB stated in P.U. 19 (2003):

"Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:

- commensurate with return on investments of similar risk;
- sufficient to assure financial integrity; and
- sufficient to attract necessary capital.

The fair return principle is consistent with both Section 80(1) of the *Act* and Section 3(a)(iii) of the *EPCA*."

The legal precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk.[13]

[12] The principal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*. B

[13] In Commission Order G-14-06 (March 2, 2006), the British Columbia Utilities Commission recognized "the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other,

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities. A fair return preserves the financial integrity of the utility, that is, it permits the utility to maintain its creditworthiness, as demonstrated by the level of its credit metrics and debt ratings. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, may potentially degrade the quality of service or deprive existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers.

neither is one subsumed by the other." See Appendix A for further discussion of the distinction between the capital attraction and comparable returns standards.

IV. FRAMEWORK FOR EVALUATION OF CAPITAL STRUCTURE AND ROE

A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm. For utilities, the business risks also include regulatory risks, i.e., the regulatory framework under which the utility operates. The prevailing regulatory framework effectively represents the current allocation of the fundamental business risks between investors and ratepayers. Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares – to finance a portion of its assets. The capital structure, comprised of debt, preferred shares and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine the fair return. The first approach entails acceptance of the utility's actual capital structure for regulatory purposes or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (fundamental business, regulatory and financial) risk of the regulated company to those of the proxy companies used to estimate the cost of equity. If the total risk of the proxy companies is higher or lower than that of the specific utility, the proxies' estimated cost of equity needs to be adjusted upward or downward to arrive at the cost of equity of the specific utility.

The first approach, varying both capital structures and ROEs, is used by the British Columbia Utilities Commission (BCUC), the Ontario Energy Board (OEB) and the Régie de l'Énergie de Québec (Régie).

The second approach assesses the utility's fundamental business and regulatory risks, and then establish a capital structure that is both compatible with those risks and that permits the application of a cost of equity determined by reference to proxy companies, with no adjustment to that cost. This approach can be applied to a spectrum of regulated companies within a range of combined fundamental business and regulatory risks.

The National Energy Board (NEB) employed the second approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995.[14] It is also the approach that was adopted by the former Alberta Energy and Utilities Board (EUB) in its Generic Cost of Capital Decision 2004-052 in 2004. In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of

[14] In its Reasons for Decision RH-1-2008 (March 2009), the NEB recognized the inextricable link between ROE and capital structure. However, it did not specify either an ROE or a capital structure for TQM. Instead, it adopted an overall cost of capital and left it to TQM to choose its optimal capital structure. The NEB also noted that the overall cost of capital approach enables comparisons of returns on an equal footing between companies of comparable risk.

the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard. Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards.

For NP, I have relied on the second approach. Specifically, I analyzed NP's requested forecast capital structure, based on the principles set out in Section V.B. I then determined whether, with the proposed capital structure, NP would face a similar level of investment risk to a benchmark Canadian utility.

B. CONCEPT OF BENCHMARK UTILITY AND BENCHMARK ROE

The ROE applicable to the benchmark utility (i.e., the benchmark ROE) is derived from market data which includes utilities from various industries (electric, gas distribution and gas pipeline). The cost of equity, as estimated using tests applied to samples of proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. For the proxy companies' cost of equity to be equivalent to the "benchmark cost of equity" applicable to the "benchmark utility", the benchmark utility's total risk needs to be similar to that of the proxy companies. If it is not, the solutions include (1) changing the benchmark utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the benchmark utility; or (3) some combination of (1) and (2).

To minimize the extent to which such adjustments are required, the point of departure should be the selection of companies that are of relatively similar total risk to the benchmark utility. In the Canadian context, there are only seven[15] publicly-traded Canadian utilities.

[15] AltaGas Utility Group (spun off from AltaGas Income Trust in late 2005), Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas and TransCanada Corporation.

These companies are relatively heterogeneous in terms of both operations[16] and size.[17] While the Canadian utilities provide some perspective, a more accurate assessment of the cost of capital for the benchmark utility can be made by reliance on a sample of comparable risk U.S. utilities drawn from a much broader universe. The selection of the sample relies on criteria designed to (1) identify companies that are of relatively similar risk to the benchmark utility and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

One objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve debt ratings in the A category. Designation of the debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category. The estimation of the benchmark return on equity must then be derived from proxy groups whose total risk permits them to achieve debt ratings in the A category.

[16] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.
[17] Ranging from an equity market capitalization of approximately \$40 million (AltaGas) to \$20 billion (TransCanada).

V. CAPITAL STRUCTURE FOR NP

A. PROPOSED CAPITAL STRUCTURE OF NP

NP is requesting that the Commission approve its forecast actual capital structure which includes a common equity ratio of 45%.

B. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION

The following principles should be respected when establishing both the cost of capital generally and a reasonable capital structure for NP:

1. The Stand-Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity
4. Ability to Attract Capital on Reasonable Terms and Conditions
5. Comparability of Returns

Each of these five principles is defined below. The five principles which apply to the determination of a reasonable capital structure include the three standards (Principles 3 to 5) which govern a fair return identified in Section III above, reflecting the interdependence between capital structure and ROE.

B.1. <u>The Stand-Alone Principle</u>

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. As NP is a stand-alone regulated entity which raises its own debt on the strength of its own business and financial risk profile, the application of the stand-alone principle is not an issue.

B.2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. The fundamental business risks of a utility include demand, competitive, supply, operating, technology-related and political risks. Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between the utility's customers and its investors.

B.3. Maintenance of Creditworthiness/Financial Integrity

A reasonable capital structure for NP, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it.

The importance of credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in the BBB/Baa[18] category) faces a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with BBB/Baa ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market. NP is principally financing long-term assets. Thus the Company needs to maintain the financing flexibility required to be able to access debt with terms to maturity in the range of 10 to 30 years in both strong and weak capital market conditions.

If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of the additional debt that the company needs to raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

B.4. Ability to Attract Capital on Reasonable Terms and Conditions

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus BBB rated debt varies with market conditions, but ratings in the BBB category can be very costly to ratepayers. As the recent global market crisis has demonstrated, capital markets can deteriorate rapidly.

Since the beginning of 2007, spreads for utilities with ratings in the A category have increased materially; utilities with ratings in the BBB category have increased by an even greater amount, as illustrated in the table below. The lack of an indicated 30-year new issue spread in January 2009 for TransAlta in that table signifies that TransAlta would likely not have been able to raise 30-year debt at that time.

[18] BBB is the DBRS and Standard Poor's medium grade ratings designation; Baa is the corresponding Moody's designation.

Table 1

	Debt Ratings DBRS/Moody's/S&P	Term of Issue	Indicated Spread at 1/2/2007	Indicated Spread at 1/8/2008	Indicated Spread at 1/5/2009	Change in Indicated Spread 2009/2007
CU Inc.	A(high)/ - / A	10 yr	53	100	320	+267
		30 yr	92	125	345	+253
Enbridge Gas	A/ - / A-	10 yr	56	110	355	+299
		30 yr	95	130	360	+265
Terasen Gas	A/ A3 / A	10 yr	70	100	355	+285
		30 yr	130	125	380	+250
Epcor Utilities	A(low) / - / BBB+	10 yr	75	140	480	+405
		30 yr	135	195	505	+370
Nova Scotia Power	A(low) / Baa1 / BBB	10 yr	75	140	420	+345
		30 yr	138	170	445	+307
TransAlta	BBB / Baa2 / BBB	10 yr	135	355	600	+465
		30 yr	300	380	N/A	N/A
Union Gas	A/ - /BBB+	10 yr	57	130	370	+313
		30 yr	107	150	395	+288
Westcoast	A(low)/ - /BBB+	10 yr	63	135	410	+347
		30 yr	118	155	435	+317

Source: RBC Capital Markets, *Indicative New Issue Pricing*, various issues.

While credit spreads have narrowed since their January 2009 peak,[19] this table underscores the potential magnitude of the incremental costs that are associated with being a BBB rated issuer, and the importance from both a cost and market access perspective of maintaining ratings in the A category. It bears noting that, in the case of a downgrade, the increased cost of debt would be borne by ratepayers over the full life of the issues.

In assessing the importance of maintaining strong A ratings, it is important to consider the relatively small size of the BBB market in Canada. As reported in "Back to Basics" by Marlene K. Puffer, *Canadian Investment Review*, Fall 2006, the BBB corporate debt market is only 4% of the total market and it is mainly limited to issues with terms under 10 years. Many institutional investors such as pension funds face limits on the proportion of BBB

[19] The spread for a new NP 30-year First Mortgage Bond issue in May 2009 was 275 basis points. At the time of its last 30-year issue in August 2007, the spread was 140 basis points, and when it did its 2005 issue, the spread was 106 basis points.

rated debt they are allowed to hold in their portfolios or cannot invest in BBB rated debt at all.[20] The small size of the Canadian market for BBB rated debt and the limitations on the ability of BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

From January 2006 to March 2009, RBC Capital Markets[21] recorded $164 billion (452 issues) of corporate debt financing in Canada. Of that amount, companies all of whose ratings were in the BBB category or below accounted for approximately 6% and 9% of the total dollar value and number of issues respectively. Even when companies with one rating in the A category (i.e., split-rated A/BBB category or lower) are included, those issues account for only 13% and 17% of the total value and number of issues respectively. From mid-2007 to March 2009, during which the credit markets have been experiencing various degrees of turmoil, of 189 reported issues, only seven were by companies with all ratings in the BBB category or lower, none of which was for a term in excess of 10 years.

Utilities need to be able to raise capital on demand. While the capital markets were very robust and open to new utility issues when NP's capital structure and ROE were set in December 2007, the current financial crisis underscores how quickly markets can change.

NP will be competing for capital in markets that may be characterized by an unprecedented requirement for regulated infrastructure capital. Its peers are increasingly global, not solely Canadian.[22] In its 2008 *World Energy Outlook*, the International Energy Agency estimated

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[20] The NEB reported in its August 2005 *Canadian HydroCarbon Transportation System Report* that Canadian bonds are an important revenue source to pension funds and other institutional investors, and a downgrade could require institutional holders to sell a large percentage of their bonds at discounted prices.

[21] RBC Capital Markets, *Credit Weekly*, various issues.

[22] Comparisons among utilities across borders, particularly by the bond rating agencies, are common. For example, S&P's peer comparison for AltaLink includes American Transmission Company and International Transmission Company, both U.S. companies (Standard and Poor's, *Research: Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity… and Profits*, April 26, 2006). Hydro One's peers include Consolidated Edison and National Grid, one a U.S. company and one a U.K. company with extensive U.S. holdings (Standard & Poor's *Peer Comparison: Consolidated Edison Inc., Hydro One Inc. and National Grid PLC – Same Ratings, Different Basis,* October 11, 2005). TransAlta Corporation's peers include PPL Corporation and Constellation Energy, both U.S. electric utilities (Standard and Poor's, *TransAlta Corp*, October 22, 2008). Ontario Power Generation's peers have included two Canadian companies

that between 2007 and 2030 close to $4.3 trillion in investment would be required by the electricity ($2.6 trillion, of which over $1.3 trillion is transmission and distribution) and gas transmission and distribution ($1.6 trillion) industries in North America.[23] To compete successfully for the required capital, that is, to continue to be able to attract capital on flexible terms and conditions, NP will require financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of their peers. Competition for capital to address infrastructure investment requirements in North America (and globally) supports a strengthening of NP's financial parameters.

B.5. <u>Comparability of Returns</u>

The combination of the adopted capital structure and return on capital should be comparable to the returns of comparable risk companies.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that NP competes for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies, both within Canada and globally. The achievement of comparability requires explicit recognition of the financial parameters of the companies of comparable risk to NP, including regulated companies throughout North America.[24]

(TransAlta and Emera) and a U.S. company, Exelon (Standard and Poor's, *Research: Ontario Power Generation Inc.*, December 9, 2005).

[23] Approximately $19 trillion world-wide (Table 2.4).

[24] The Conference Board of Canada has pointed out the importance of comparable returns for electric transmission in Canada. In its May 2004 Briefing entitled, "Electricity Restructuring: Opening Power Markets", the Conference Board stated,

> *"Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid."*

C. BUSINESS RISK PROFILE OF NP

NP's business risk profile is in large part defined by the demographics and growth prospects of its service area.

In recent years, the economy of Newfoundland and Labrador has benefitted from the development of offshore resources, which has, according to DBRS, led to increased wealth, substantially boosted economic activity and diversification.[25] Real growth in 2007 hit 9.3% in 2007, compared to 2.5% for Canada as a whole. From 2000-2007, real growth in Newfoundland and Labrador outstripped all other provinces, averaging 5.0%, compared to 3.0% for Canada and 4.0% for the second best performer, Alberta.[26] With the support of strong oil prices and royalty revenues, the provincial government posted a budget surplus in fiscal 2007-2008.

In 2008, impacted by an increasingly difficult global economy during the second half of the year, growth in the Province contracted slightly (-0.1%) compared to overall growth in Canada of only 0.5%. However, despite the reduction, a fourth consecutive budget surplus was achieved in 2008-2009.[27]

For 2009, the Provincial government forecasts that real GDP growth will decline sharply (-7.7%) due to a decline in exports of oil, minerals and newsprint, although the expected decline is much less severe (-1.3%) when adjusted for income earned by non-resident owners of provincial resource-related mega-projects.[28] Other indicators also point to a more moderate downturn. For example, the government's forecasts include positive real growth in

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The comments of the Conference Board with respect to electric transmission are no less true of any of the other electric utility functions.

[25] DBRS, *Rating Report: Province of Newfoundland and Labrador*, October 28, 2008.

[26] ScotiaBank Group, *Global Economic Research, Global Forecast Update*, May 1, 2009.

[27] Newfoundland and Labrador, *2009 Provincial Budget-Highlights* and ScotiaBank Group, *Ibid.*

[28] Newfoundland and Labrador, *The Economy 2009*. Other forecasts are for much lower declines. For example, the Conference Board of Canada's most recent long-term Provincial Forecast anticipates a reduction of only 1% in 2009; ScotiaBank Group's May 1, 2009 forecast is for a decline in real GDP of 2.8% in 2009.

personal income, strong capital investment and housing starts on par with those experienced in 2007. The Provincial government's announcement prior to the March release of its 2009 budget that it would significantly increase infrastructure spending is expected to cushion the effects of the global downturn.

In the medium term (2010-2012), aided by the impacts of the government's stimulus spending and expected private investment in the resource sector, real GDP growth is expected to be modest compared to 2000-2007 (forecast at 2.6% by the Conference Board), but growth in personal disposable income is expected to remain relatively robust (4.3%).

Over the longer-term, the Conference Board of Canada expects the real growth in GDP of Newfoundland and Labrador to lag the rest of Canada, From 2013-2030, the Conference Board of Canada expects real annual GDP growth in the province to average 0.4%, compared to 2.0% for Canada. The slow growth outlook reflects the decline in the contribution of the oil and mining sectors to the overall economy as resources are depleted and the impacts on the economy of a declining population.

Other forecast key economic indicators over the longer-term (2013-2030), compared to those for Canada as a whole, include the following:

Table 2

	Newfoundland and Labrador	**Canada**
Personal Disposable Income	2.3%	3.8%
Retail Sales	2.4%	3.9%
Housing Starts	-6.7%	-0.7%
Population	-0.3%	1.0%
Employment	-0.8%	0.7%
Service Producing Industries	0.6%	1.9%

Source: The Conference Board of Canada, *Provincial Outlook 2009, Long-Term Economic Forecast*, February 2009 (Tables 1, 2 and 12-21).

While housing starts are forecast to grow by over 5% per year from 2013 to 2016, over the long-term, as indicated in the table above, they are expected to decline. Growth in both the service producing industries and in personal disposable income, which are key to NP's growth prospects, are expected to be low relative to the rest of the country over the long-term.

Low customer growth in the longer-term, combined with low income growth, and potentially high fuel prices will tend to put downward pressure on customer consumption. Lower margins due to persistent reductions in customer usage, particularly for companies like NP with a significant heating load have become a significant issue. In addition, the 2007 Newfoundland and Labrador Energy Plan encourages reduction in residential and commercial energy which NP has addressed in its five-year customer conservation plan filed with the PUB in mid-2008. The declining usage per customer issue is being increasingly addressed by North American utilities through decoupling mechanisms which provide protection from a decline in revenues due to lower usage per customer.

For NP, the declining customer usage issue is compounded by migration from rural to urban areas. New investment must be made to serve customers who have moved to urban areas, increasing the total investment that must be recovered, but from essentially the same and potentially a declining total customer base. The increased unit costs, in turn, act as an incentive for customers to reduce electricity consumption.

Partially offsetting the low growth prospects is NP's high capture rate (approximately 90% of new construction) of new urban customers. The high capture rate arises partly as a result of relative cost versus home heating oil and partly as a result of the strict regulations governing the use of fuel oil. The high capture rate of new construction supports increased consumption in the near-term.

On balance, the long-term outlook for the service area has not changed materially since NP's last general rate application in 2007.

With respect to supply and physical risks, NP continues to rely on Newfoundland and Labrador Hydro (NLH) for over 90% of its power supply. DBRS continues to view NP's reliance on NLH for most of its supply as a challenge (*Rating Report, Newfoundland Power Inc.,* May 5, 2008). Moody's also takes note of NP's dependence on NLH for its supply, although it concludes that NP's dependence on NLH is somewhat offset by the insulation from potential competition. While NP has no plans to build additional generating facilities, and its dependence on NLH will gradually increase, supply risks have not changed materially since NP's last general rate application in 2007.

The regulatory framework in the province remains constructive. NP has a weather normalization mechanism and a rate stabilization mechanism to allow for pass-through of variations between forecast and actual fuel costs. The latter contains mechanisms for to account for both energy and demand variances, limiting NP's exposure to both fluctuations in costs of fuel oil and customer demand.

In summary, the business risk profile of NP has not changed materially since its last GRA in 2007.

D. BOND RATINGS AND CREDIT METRICS

NP's debt is currently rated by two major debt rating agencies, Moody's and DBRS. Moody's debt rating, at Baa1 for senior secured debentures, is the lower rating. NP's DBRS rating is A for senior secured debentures. The most recent bond rating reports from both rating agencies indicate no material changes in business risk. Moody's March 2009 credit opinion shows improvement in NP's credit metrics in 2008, following a gradual deterioration from 2003-2007.

Moody's ratings from highest to lowest are as follows:

Table 3

Rating	Rating Definition
Aaa	Highest quality with minimal credit risk
Aa	High quality with very low credit risk
A	Upper medium credit with low credit risk
Baa	Medium grade with moderate credit risk; may possess certain speculative elements
Ba	Have speculative elements and are subject to substantial credit risk
B	Speculative and subject to high credit risk
Caa	Of poor standing and subject to very high credit risk

To ratings within each major category, a modifier of 1 to 3 is appended, with 1 meaning that the obligation ranks in the upper end of its generic rating category and 3 means that the obligation ranks at the lower end of its generic rating category. Ratings of Baa3 or higher are considered investment grade.

Moody's has maintained the debt rating for NP at Baa1 with a Stable Outlook since the initial rating was assigned in June 2005. The rating reflects Moody's conclusion that NP is operationally and financially independent from its parent ("ring-fenced"). Moody's has referenced the regulatory environment, low risk transmission and distribution operations, lack of competitive pressures, and low predictable growth as NP's key strengths from a business risk perspective.

Moody's publishes quantitative guidelines[29] for utility ratings for two business risk categories, "low" and "medium" risk.[30] The guidelines for the "low" business risk category and both the A and Baa ratings categories, compared to NP's actual 2008 metrics are as follows:

[29] DBRS publishes broad guidelines for A/BBB ratings, but they do not distinguish by either business risk or investment-grade rating category.

[30] *Ibid*., p.3. The guidelines were originally published in March 2005 in Moody's Investor Services, *Rating Methodology: Global Regulated Electric Utilities*. New guidelines are anticipated this year.

Table 4

	A	Baa	NP (2008)
FFO Interest Coverage	3.0-5.7x	2.0-4.0x	3.1X
FFO/Debt	12-22%	5-13%	15.8%
Retained Cash Flow/Debt	9-20%	3-10%	12.4%
Debt/Capital	50-75%	60-75%	54.4%

Note: FFO is funds from operations which equals net income plus depreciation, amortization and deferred taxes.

Sources: Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 and *Credit Opinion: Newfoundland Power Inc.*, March 2009

NP's most recent achieved ratios position it in the A3/ Baa1 rating category, reflecting a material improvement from 2007. Moody's notes that NP's ratios are expected to strengthen but continue to remain somewhat weaker than other low risk Baa1 rated companies predominantly engaged in electricity transmission and distribution operations. Moody's expects that NP's FFO/Debt ratio will continue to be 15% or higher and the FFO to Interest Coverage Ratio will remain at or above 3 times. Moody's considers a downward revision in NP's rating to be unlikely. However, in the event that NP experiences a sustained deterioration in metrics, i.e., FFO/Debt ratios below the low teens, FFO interest coverage of less than 2.5X and debt/capital in excess of 55%, NPI's long-term ratings could be negatively impacted.

Similarly Moody's considers an upward revision in NPI's rating to be unlikely in the near term, but it could be positively impacted if there were a sustainable improvement in financial ratios, such as FFO interest coverage above 4.0x and FFO/Debt in the high teens. This level of improvement could result from further rate increases, coupled with either an increase in equity in the capital structure or a higher equity risk premium utilized by the regulator to automatically adjust the allowed rate of return on rate base between full cost of capital hearings.

With respect to DBRS, its ratings of NP's senior secured debt have consistently been A with a Stable trend. DBRS continues to view NP's principal business strengths to be its regulatory framework, stable customer base and minimal competitive pressures. The key challenges are related to its reliance on Newfoundland and Labrador Hydro for the preponderance of its power supply, the sensitivity of its earnings to interest rates (as a result of the automatic adjustment mechanism for return), managing forecast risk and limited growth potential. DBRS also notes that higher rates, including increases driven by the rising cost of oil in recent years, may lead to energy conservation by customers, which could have a negative impact on sales volumes and earnings.

The following table provides a comparison of NP's financial metrics to the U.S. utilities which are included in the proxy sample of U.S. utilities used to estimate the cost of equity (See Chapter VI), as well as to the universe of U.S. electric and gas utilities with ratings in the A category by Standard & Poor's.[31] NP is comparable to its Canadian and U.S. peers with respect to actual capital structure, but its other metrics have been weaker than both the average Canadian utility and A rated U.S. utilities.

[31] While NP is no longer rated by S&P, the preponderance of Canadian utilities that issue debt are rated by S&P as are the preponderance of U.S. utilities.

Table 5

Company/Sample	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2008)	EBIT Interest Coverage (2005-2007)	FFO to Total Debt (2005-2007)	FFO Interest Coverage (2005-2007)
NP	A/Baa1/-	45.5%[1/]	2.3x	9.1%	2.7x
Canadian Utilities with Rated Debt (All)	A/A3/A-	40.4%	2.5x	14.5%	3.2x
U.S. A-Rated Electric (All)	-/A3/A-	46.7%	3.6X	21.6%	4.8x
U.S. Proxy Utility Sample	-/A3/A	41.9%	3.6x	21.3%	4.5x

Definitions:

Earnings before Interest and Taxes (EBIT) Interest Coverage: Operating income divided by interest expense.

Funds from Operations (FFO) to Total Debt: FFO equals net income plus depreciation, amortization and deferred taxes. FFO to debt equals FFO divided by total debt.

Funds from Operations (FFO) Interest Coverage: FFO plus interest expense divided by interest expense.

[1/] 2008.

Source: Schedules 4, 5, 6 and 15

As the table above demonstrates, the credit metrics of NP and Canadian utilities generally compare unfavourably to their U.S. peers.[32] In other words, they are competing for capital

[32] The average actual common equity ratio of Canadian utilities is higher than the typical common equity ratio adopted (deemed) for regulatory purposes. Both DBRS and Standard & Poor's consider the equity ratios adopted for Canadian utilities to be thin (and the allowed equity returns relatively low).

For example, in reference to FortisAlberta, DBRS commented that:

> In Alberta, as well as in many other jurisdictions in Canada, the rates of return and equity capitalization for ratemaking purposes allowed by regulators have been low in recent years, largely as a result of the low interest rate environment. This has had a negative impact on earnings and cash flows. FortisAlberta's equity thickness at 37% and low ROE's directly impact shareholder returns, hindering the ability to attract capital for capital expenditure purposes. In addition, the allowed ROEs

with U.S. utilities with stronger financial metrics.[1] Moreover, as utility debt yield spreads between Canada and the U.S have converged, Canadian utilities no longer have a built-in domestic cost advantage in raising capital.[33] In setting the allowed return, (the capital structure as well as the ROE), the PUB needs to recognize that Canadian utilities generally and NP specifically should be allowed to achieve a degree of financing flexibility which is comparable to that of its North American peers.

The actual credit metrics of U.S. utilities reflect the returns (a combination of the ROE and capital structure) that are awarded by regulators. From 2006-March 2009, the average common equity ratio adopted by U.S. regulators for electric and gas distribution utilities with was approximately 48% with corresponding awarded ROEs averaging 10.4%.

E. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE

Within a reasonable range, the capital structure for a particular utility is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. In my opinion, NP's forecast capital structure, containing 45% common equity, is reasonable, for the reasons summarized below.

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are significantly below those allowed for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities because they can earn higher rates of return in the U.S. from businesses having similar business risk profiles. (DBRS, *Credit Rating Report: FortisAlberta*, November 25, 2005).

In general, S&P considers that Canadian utility financial policies tend to be aggressive with leverage, and regulators parsimonious with returns. (Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006. The "aggressive leverage" is largely a result of regulatory directives, as noted by S&P in its March 2003 report entitled *Canadian Regulation Reassessed as a Ratings Factor*. In that report S&P had noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives.

[33] Over the ten year period ending December 2005, for example, the average yield spread between long-term A rated Canadian utility and long-term Canada bonds was approximately 40 basis points lower than the corresponding yield spread between U.S. long-term A rated utility and Treasury bonds. Since the elimination of the Foreign Property Rule (FPR) in 2005, the spreads have converged. From January 2006 to the end of March 2009, on average the spreads in Canada and the U.S. have been virtually identical (differential less than 10 basis points).

1. There has been no material change in the level of business risk to which NP is exposed since the last time the capital structure was reviewed which would warrant a change in the capital structure.

2. NP's credit metrics, which are partly dependent on capital structure, are adequate for its ratings at the existing capital structure, but are weaker than companies in the same Moody's rating category.

3. With the further global integration of the Canadian capital markets, particularly with the termination of the Foreign Property Rule, a strengthening of NP's financial parameters is warranted to provide the ability to offer a return compensatory with its risk and comparable to those of its global peers.

4. The forecast North American and global investment requirements for infrastructure point to significant competition for capital going forward. NP should be positioned so that it can compete successfully, that is, continue to obtain capital as required on reasonable terms and conditions. At the existing capital structure and ROE, NP's credit metrics compare unfavourably to those of its U.S. peers.

At the forecast capital structure, NP would be viewed by investors as an approximately average risk utility relative to its Canadian peers. The ROE for a benchmark utility estimated in Chapter VI below is applicable to NP with no adjustments required either for higher or lower total risk.

VI. FAIR RETURN ON EQUITY

A. APPROACH TO ESTIMATION OF RETURN ON EQUITY

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity: equity risk premium, discounted cash flow and comparable earnings tests. Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[34] Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions.[35] These considerations not only emphasize the importance of reliance on multiple tests, but also of benchmarking, or testing the reasonableness of the test results themselves against other relevant information.

Moreover, the criteria that define a fair return, set forth in Chapter II, give rise to two separate standards, the capital attraction standard and the comparable returns standard. A fair and reasonable return gives weight to both the cost of attracting capital standard and

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[34] For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[35] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> "Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position."

comparable returns standard.[36] The requirements of the two standards are met using different types of tests. The equity risk premium and discounted cash flow tests establish the cost of attracting capital. The comparable earnings test is one measure of the comparable returns standard. To establish a fair return on equity for NP, I have applied all three. The application of each of the tests is discussed in the sections below.

B. EQUITY RISK PREMIUM TESTS

B.1. Conceptual Underpinnings

An equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks[37] and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

[36] Appendix A discusses the distinctions between the two standards.
[37] To illustrate, as discussed in Section II above, as demonstrated by the MVX index in Canada, equity market volatility has picked up significantly and investor risk aversion has increased in the period since NP last appeared before the PUB as investors have become less sanguine about the future of the equity market.

B.2. <u>Risk-Free Rate</u>

The application of equity risk premium tests require a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable.

For the purpose of applying the equity risk premium tests, the estimated long-term Canada bond yield is 4.25%. The estimate relies as a point of departure on the April 2009 Consensus Forecasts' 3.1% 10-year Canada bond yield forecast for April 2010,[38] which, with a current 0.75% spread between 10-year and 30-year Canada bond yields, results in a yield of 3.85%. It is reasonable to expect that long-term Canada bond yields will rise during 2010 as the economy strengthens. A 4.25% long-term Canada bond yield forecast for 2010 reflects increases in yield of approximately 0.2% per quarter throughout the year, and is consistent with a gradual upward trend toward the forecast yield expected to prevail over the longer term of approximately 5.25%.[39]

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[38] Consensus Economics does not provide a forecast of the 30-year Canada bond yield, nor does it provide a forecast of 10-year Canada bond yields for all of 2010.

[39] Consensus Economics, *Consensus Forecasts,* April 2009 forecast the average 10-year Canada bond yield from 2011-2019 at approximately 5.0%. The spread between 10-year and 30-year long term Canada bond yields has historically averaged approximately 35 basis points.

B.3. Risk-Adjusted Equity Market Risk Premium Test

B.3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required utility equity risk premium entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required utility equity risk premium. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor **should** require (in contrast to what the investor **does** require). Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing sole reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Appendix B.

B.3.b. Equity Market Risk Premium

B.3.b.(1) Globalization and Relevance of U.S. Equity Market Experience

My estimate of the expected/required equity market risk premium was made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but should also take into account the U.S. equity market as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

The historic Canadian equity and government bond returns incorporate various factors that make them questionable as a realistic representation of expected risk premiums (e.g., capital held captive in Canada as a matter of policy, lack of equity market liquidity and diversity, and the higher risk of the Government of Canada bond market historically, which has since dissipated). These factors are set out in Appendix B.

Of particular importance has been the historic impact of the Foreign Property Rule (FPR), which capped the proportion of foreign investment that could be held by individuals (in RRSPs) and by pension funds. The combination of mediocre returns and small size of the Canadian market relative to the total global market (approximately 2%) put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. This cap had been as low as 10% of the book value of assets (from 1971 to 1990) and was at 30% when it was removed entirely in 2005.[40] Historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases

[40] From 1957 to 1971 no more than 10% of income could come from foreign sources.

of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases declined in 2008, they were still almost $750 billion during the first eleven months of the year. In mid-2008, although the total percentage of foreign assets in trusteed pension funds was less than 30%, the percentage of foreign equity to total equity was close to 45%.[41, 42]

The relevance of the U.S. experience to the estimation of the risk premium from a Canadian perspective has increased as the relationship between Canadian and U.S. interest rates has changed. Historically, much of the difference between the achieved risk premiums in Canada and the U.S. arises from higher interest rates in Canada. With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the relative risk of investing in Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bond yields and returns that existed historically has been substantially reduced. Over the period 1926-1996, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points. Between 1997 and 2008, the difference was approximately -20 basis points.

The most recent consensus of long-term forecasts of government bond yields anticipates that 10-year government bond yields will be virtually identical in the two countries, at approximately 5.0% for Canada and 5.2% for the U.S. over the period 2011-2019 (Consensus Economics, *Consensus Forecasts,* April 2009).[43] With similar interest rates in the two countries going forward, the U.S. historic equity market risk premium is a relevant benchmark in the estimation of the forward-looking equity market risk premium for Canadian investors.

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[41] Based on market value. On a book value basis, the proportion of foreign assets in the pension funds is closer to 33% and over 50% of all equity investment is foreign. Statistics Canada, Table 280-0003.

[42] Pension funds are increasingly investing in infrastructure assets outside of Canada. For example, a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board are in the process of acquiring Puget Energy, an electric and gas utility serving northern Washington State. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.15% on a 46% common equity ratio, adopted in October 2008.

[43] Blue Chip *Economic Indicators* (March 2009), which canvasses economic forecasters at 50 financial institutions, anticipates a 10-year U.S. Treasury yield of 5.25% from 2011-2020.

On the equity side of the equation, the Canadian equity market composite is dominated by two sectors, financial services and energy. These two sectors alone accounted for approximately 57% of the total market capitalization of the S&P/TSX Composite at the end of December 2008. In contrast to the S&P/TSX Composite, the historic U.S. equity returns have been generated by a more diversified and liquid market. In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Approximately 47% of Canadian portfolio investment in foreign equities at the end of 2007 was in the U.S.[44] The diversified nature of the U.S. equity market and the close relationship between the Canadian and U.S. capital markets and economies warrant giving significant weight to U.S. historical equity risk premiums in the estimation of the required equity risk premium for Canadian utilities.

B.3.b.(2) The Post-World War II Period

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, I focused on post-World War II returns, that is, 1947-2008, a period more closely aligned with what today's investors are likely to anticipate over the longer-term.[45] I have also taken account of achieved returns and risk premiums over longer periods.

[44] Statistics Canada, *Canada's International Investment Position – Fourth Quarter 2008*. Of the remaining 53%, the next largest allocation of foreign portfolio equity investment is the U.K., which accounted for 11%.

[45] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

B.3.b.(3) Historic Risk Premiums from 1947-2008

As previously indicated, in arriving at an estimation of the market risk premium, my point of departure was both Canadian and U.S. historic returns and risk premiums during the post-World War II period. The average U.S. and Canadian historic risk premiums during that period were as follows:

Table 6

Historic Risk Premiums Arithmetic Averages (1947-2008)		
	Versus Bond Total Returns	**Versus Bond Income Returns**
Canada	4.6%	4.4%
U.S.	5.6%	6.2%

Source: Schedule 8.

B.3.b.(4) Superiority of Arithmetic Averages

When historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages, not geometric (compound) averages, should be used. The geometric average, which is appropriate for use in describing historic portfolio performance, represents the achieved return as if it had been a constant average annual return. Using the arithmetic average of all past returns recognizes the probability distribution of future outcomes based on past variations in annual returns. Expressed simply, the arithmetic average recognizes the uncertainty in the stock market; the geometric average removes the uncertainty by smoothing over annual differences. (See Appendix B for further discussion).

B.3.b.(5) Income Returns versus Total Bond Returns

The application of the CAPM requires the estimation of the market return in relation to the risk-free rate. While government bonds are considered default-free, they are not risk-free; they are subject to interest rate risk. The total bond returns experienced include capital gains and losses resulting from changes in interest rates over time. The bond income return, in contrast, reflects only the bond coupon payment portion of the total bond return; it represents the riskless component of the bond return. In principle, using the bond income return more accurately measures the historic equity risk premium above the risk-free rate.

B.3.b.(6) Historic Risk Premiums and Price/Earnings Ratios

The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

I have analyzed the trends in P/E ratios, equity market returns, and bond returns.[46] That analysis demonstrates:

(1) The increase in price/earnings ratios experienced during the market bubble of the 1990s has not resulted in a higher and unsustainable level of equity market returns. The arithmetic average equity returns in both Canada and the U.S. from 1947-1988 (prior to the increase in P/E ratios commencing in 1989) are actually higher than the average returns for the full 1947-2008 period.

(2) An analysis of rolling 10-year average equity returns reveals no upward or downward trend in equity market returns in Canada or the U.S. over the post World War II period.

[46] See Appendix B for further discussion.

(3) The observed decline in the experienced risk premium over the 1947-2008 period, particularly in Canada, is due largely to an increase in bond returns, not a decline in equity returns. The historic bond returns in Canada (both total and income returns) are significantly higher (at approximately 7.0%) than the forecast yields on long-term Canada bonds of 4.25% for 2010 and 5.25% over the longer-term.

In summary, the historic equity market returns in both Canada and the U.S. provide a reasonable estimate of the forward looking equity market return. In contrast, the Canadian historic bond returns are materially higher than the expected returns. Thus, the historic measured risk premium in Canada understates a reasonable estimate of the forward-looking equity market risk premium.

B.3.b.(7) Comparison of Longer-Period Returns to Post-World War II Returns

A comparison of the longer-term returns and equity risk premiums in Canada and the U.S. to the post-World War II returns demonstrates that the average returns for the equity markets have not changed materially. Over the long-term, on average, the equity market return in both countries has been in the range of 11.0%-12.0%.

Table 7

	Canada		U.S.	
	1924-2008	1947-2008	1926-2008	1947-2008
Equity Market Return	11.3%	11.6%	11.7%	12.2%

Source: Schedule 8.

B.3.b.(8) Estimate of Equity Market Risk Premium

Given the absence of any material upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.0%-12.0%, based on both the Canadian and U.S. equity market returns. Based on both the near-term (2010) and the longer-term forecasts for long-term Canada bond yields of 4.25% and

5.25% respectively, and an expected equity market return in the range of 11.0%-12.0%, the indicated equity market risk premium is approximately 6.75%.

B.3.c. Relative Risk Adjustment

B.3.c.(1) Total Market Risk

The market risk premium result needs to be adjusted to recognize the relatively lower risk of utilities. My analysis of the relative risk adjustment starts with a recognition that investors are not perfectly diversified, do look at the risks of individual investments, and require compensation for assuming company-specific or investment-specific risk. It also recognizes that, while investors can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot. Thus, a risk measurement that reflects those considerations is relevant for estimating the utility equity risk premium. These considerations support focusing on total market risk, as well as on beta, which is intended to measure solely non-diversifiable risk. The drawbacks of beta as the sole measure of risk, as well as the absence of an observable relationship between "raw" betas[47] and the achieved market returns on equity in the Canadian market, provide further support for reliance on other measures of risk to estimate the required equity return (see Appendix B).

The standard deviation of market returns is the principal measurement of total market risk. To compare the relative total risk of Canadian utilities, I calculated the standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, over five-year periods ending 1997 through 2008 (Schedule 10).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of

[47] The "raw" beta refers to the simple regression between the monthly percentage changes in the price of a utility or utility index and the corresponding percentage change in the price of the equity market index (the S&P/TSX Composite).

the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 10 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

B.3.c.(2) Historic Raw Betas

Since beta is the risk measure that underpins the application of the CAPM, I also took account of utility betas to estimate the relative risk adjustment. Schedule 11 summarizes the "raw" betas I calculated for individual publicly-traded Canadian regulated gas and electric companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector using monthly price data calculated over five-year periods ending 1993 through 2008.[48]

As Schedule 11 indicates, there was a significant decline in the calculated "raw" betas of the individual Canadian utilities between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative). Following an increase in 2007 to 0.50, the utility betas again declined in 2008 to approximately 0.25. The observed levels and pattern of the calculated "raw" utility betas in 1999-2008 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the fallout of the subprime mortgage crisis; and (4) the greater sensitivity of utility stock prices relative to the equity market composite to rising and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006). Over the longer-term (1970-2008), the "raw" beta of the TSX Utilities Index was 0.50, as indicated below.

[48] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector, and no longer comprise a separate sub-index.

B.3.c.(3) Canadian Utility Returns and "Raw" Betas

The equity betas of traded Canadian utility shares and of the utility index explains a relatively small percentage of the actual achieved market returns over time. A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2008[49] shows the following:

$$\begin{array}{lcll} \begin{array}{c}\text{Monthly TSX}\\ \text{Utilities Index}\\ \text{Return}\end{array} & = & 0.0056 + 0.50 & \left\{\begin{array}{c}\text{Monthly TSE}\\ \text{Composite}\\ \text{Return}\end{array}\right\} \\ \text{t-statistic} & = & \qquad\qquad 14.9 & \\ R^2 & = & 32\% & \end{array}$$

The relationship quantified in the above equation suggests a beta of close to 0.50. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 32%. That means 68% of the monthly volatility in share prices remain unexplained.

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly long-term Canada bond returns to the analysis indicates the following:

$$\begin{array}{lcllll} \begin{array}{c}\text{Monthly TSX}\\ \text{Utilities Index}\\ \text{Return}\end{array} & = & 0.00185 + .42 & \left\{\begin{array}{c}\text{Monthly TSE}\\ \text{Composite}\\ \text{Return}\end{array}\right\} & + .53 & \left\{\begin{array}{c}\text{Monthly}\\ \text{Long Canada}\\ \text{Bond Return}\end{array}\right\} \\ \text{t-statistics} & = & \qquad 13.3 & & 9.3 & \\ R^2 & = & 43\% & & & \end{array}$$

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (43% versus 32%). The second

[49] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2008.

regression equation suggests that utility shares have had approximately 40% of the volatility of the equity market and over 50% of the volatility of the bond market, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility shares' volatility unexplained. To provide some perspective, the average actual annual return for the index over the 1970-2008 period was 12.2%. Of this average annual return, 2.25 percentage points was explained neither by volatility in the equity market nor returns of the government bond market.

Using an expected annual equity market return of 11.5%, an annual long-term Canada bond return equal to the forecast longer-term 30-year Canada yield of 5.25%, and a annual "unexplained"[50] return component equal to that achieved in the past (2.25 percentage points), the indicated utility return going forward is 10.0%. If, instead, the "unexplained" return component is assumed to be equal to the same proportion of the total return as was the case historically (18.5%), the expected utility return is approximately 9.3%. When the average of the two utility returns (9.6%) is expressed as an equity risk premium above the 5.25% forecast long-term Canada bond yield, the indicated relative risk adjustment is approximately 0.70.[51]

B.3.c.(4) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that utilities are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely,

[50] Represented by the intercept in the equation.

[51] $\frac{9.6\% - 5.25\%}{11.5\% - 5.25\%} = .70$

stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0.

The following table compares the three-year Bloomberg betas ending March 27, 2009 for the five major Canadian utilities to the calculated "raw" betas for the same three-year period. The Bloomberg betas suggest that the relative risk adjustment based on recent Canadian utility betas would be approximately 0.65. The application of the same adjustment formula to the recent three-year raw betas and the long-term calculated "raw" beta of 0.50 for Canadian utilities estimated above results in a similar relative risk adjustment of 0.67.[52]

Table 8

Company	**"Raw" Beta**	**Bloomberg Beta**
Canadian Utilities	0.41	0.61
Emera	0.38	0.59
Enbridge	0.56	0.71
Fortis	0.49	0.66
TransCanada	0.47	0.65
Median	**0.47**	**0.65**

Source: Schedule 11 and Bloomberg

A comparison of the reported *Value Line* betas for the sample of low risk U.S. utilities relied upon in the application of the discounted cash flow (DCF) and DCF-based risk premium test

[52] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.

shows a similar relationship. The "raw" calculated betas for the five-year period ending March 2009 averaged 0.41; the average reported *Value Line* beta for the sample, and the beta more likely to be relied upon by analysts and investors, was 0.66 (Schedule 15).

B.3.c.(5) Relative Risk Adjustment

The preceding analysis of standard deviations of market returns and betas supports a relative risk adjustment in the range of 0.65-0.70.

B.3.d. Utility Risk Premium and Cost Of Equity

I previously estimated the equity market risk premium at the 2010 forecast long Canada yield of 4.25% and at the longer-term yield of approximately 5.25% at approximately 6.75%. At an equity market risk premium of 6.75% and a relative risk adjustment of 0.65-0.70, the indicated utility equity risk premium is approximately 4.5%. The cost of equity based on the risk-adjusted equity market risk premium test at the 2010 forecast long-term Canada bond yield of 4.25% is 8.75%, before any adjustment for financing flexibility.

B.4. DCF-Based Equity Risk Premium Test

The risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly. That is, it estimates an equity risk premium for the equity market as a whole, and then adjusts it for the relative risk of the utility. The DCF-based risk premium test, discussed in this section and the equity risk premium test discussed in Section B.5, estimate the utility equity risk premium directly, by analyzing utility equity return data.

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model (DCF) and long-term government bond yields to estimate expected utility returns and risk premiums over time. Monthly cost of equity estimates were constructed for the period 1991-March 2009[53] using the DCF model and a sample of low risk U.S. electric and gas utilities as a proxy for NP.[54] The reasons for choosing U.S. utilities are as follows:

First, there are only six publicly-traded Canadian utilities with conventional corporate structures and with a long-term stock trading history. Second, there are insufficient forward-looking estimates of long-term growth rates for these companies that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums. A consensus estimate of investors' growth expectations is critical to the application of the discounted cash flow model. The availability of a consensus of analysts' forecasts means that the resulting growth estimate reflects the market view.

Third, U.S. utilities are reasonable proxies for estimating the cost of equity for NP. As noted in Section II, the operating environments are similar, the regulatory model in the U.S. is similar to the Canadian model,[55] and the Canadian and U.S. capital markets are significantly integrated.[56] Only relatively pure-play U.S. utilities were selected; these utilities are in the same business risk category as the typical Canadian utility[57] and have S&P debt ratings of A- or better, similar to the universe of Canadian utilities with rated debt (Schedules 6, 7 and 15). The sample contains 13 utilities, and is the same sample of companies used to perform the discounted cash flow test (Section VI.C.).

[53] The period 1991-March 2009 encompasses both a full business cycle (1991-2007) as well as data through the most recent full quarter available.

[54] The selection criteria for the proxy utilities and the construction of the DCF estimates are described in Appendix C.

[55] For example, Terasen Gas Inc., a major Canadian gas utility with a similar regulatory model to NP, is considered by Moody's to have slightly less regulatory support on average than the U.S. gas distribution utilities included in the proxy sample.

[56] A June 2007 study prepared on behalf of the Ontario Energy Board entitled *A Comparative Analysis of Return on Equity of Natural Gas Utilities* by Concentric Energy Advisors compared the gas distribution industry and capital markets in Canada and the U.S. and concluded (1) taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities; and (2) As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets.

[57] The average Canadian utility business profile score by S&P is "Excellent"; all of the utilities in the proxy sample of U.S. utilities also have an "Excellent" business profile.

The monthly DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[58] plus the expected dividend yield. The equity risk premium is equal to the difference between the sample average DCF cost of equity and the corresponding month-end 30-year Treasury bond yield.

For the sample of U.S. utilities, the DCF-based risk premium test indicates an average risk premium over the full 1991-March 2009 period of 4.3% (Schedule 12); the corresponding average long-term government bond yield was 5.9%, approximately 175 basis points higher than the 2010 forecast long-term Canada bond yield of 4.25%.

The data suggest that there has been an inverse relationship between the long-term government bond yield and utility equity risk premiums over the 1991-March 2009 period. A simple regression analysis between the monthly 30-year Treasury bond yields and the corresponding equity risk premiums over the entire 1991-March 2009 period indicates that, on average, over the full period, the equity risk premium rose by 70 basis points when the long-term government bond yield fell by 100 basis points and, conversely, the equity risk premium fell by 70 basis points when the long-term government bond yield rose by 100 basis points. Expressed in terms of ROE, the equity return rose by 30 basis points when the long-term government bond yield rose by 100 basis points. Conversely, the equity return fell by 30 basis points when the long-term government bond yield fell by 100 basis points.

This analysis indicates that the ROE is much less sensitive to changes in the long-term Canada bond yield that the existing formula assumes. The existing formula assumes that the ROE increases or decreases by 80% of the increase or decrease in the long-term Canada bond yield. The DCF-based risk premium analysis indicates that the increase or decrease in ROE has been only 30% of the increase or decrease in long-term Canada bond yields.

[58] The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

At the 2010 forecast 30-year government bond yield of 4.25%, the indicated utility equity risk premium is approximately 5.4%. The indicated cost of equity would be 9.7%. However, this analysis does not incorporate other factors which impact on the cost of equity

The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' perception of risk.[59] To capture this factor, I tested the relationship among utility equity risk premiums[60] and the spreads between long-term utility[61] and government bond yields in conjunction with the change in the yield on long-term government bond yields. To estimate this relationship, I performed a second regression analysis over the same 1991-March 2009 period (Schedule 12, page 2). The analysis indicated that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields. Specifically, the analysis showed that the equity risk premium has increased or decreased by approximately 40 basis points when the government bond yield has decreased or increased by 100 basis points and has increased or decreased by 12 basis points for every 10 basis point increase or decrease in the utility/government bond yield spread. The inclusion of the spread as a second explanatory variable also supports the conclusion that the utility cost of equity changes by significantly less than 80% of the change in the long-term government bond yields.[62]

As of the end of March 2009, the spread between the yields on a sample of long-term A rated Canadian utility bonds and 30-year Government of Canada bonds was approximately 345 basis points. Although the spreads had narrowed since their December peak of 390 basis points, the spreads remain well in excess of their historic averages as well as in excess of their historic peaks. As spreads vary over the business/interest rate cycle, spreads should narrow further as the economy improves, as has been observed historically. However, three factors suggest that the spreads will remain above their historic levels.

[59] Or, alternatively, risk aversion i.e., willingness to take risks.
[60] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[61] Based on Moody's long-term A-rated utility bond index.
[62] Similar regressions using allowed ROEs for U.S. utilities, long-term government bond yields and spreads, as discussed on page 9 above, also demonstrated that the ROE is less sensitive to the change in the government bond yield than implied by the current formula.

First, historically, the existence of the FPR and the high demand in Canada for a relatively limited supply of high quality issues kept high grade Canadian bond spreads relatively low.[63] With the elimination of the FPR, spreads on domestic bond issues will tend to converge with those of global issuers of similar risk.[64] Second, while the consensus forecast anticipates that the economy will improve in 2010 compared to 2009, the first year of recovery is expected to be relatively weak, pointing to the persistence of higher than average spreads. Third, the financial crisis has led to a global repricing of risk across various types of securities, including A rated Canadian utility bonds.

As of the beginning of April 2009, the cost of a new 30-year debt issue for Canadian A rated utilities was approximately 6.5-6.75%. While the spread with long-term Canada bonds should decline as long-term Canada bond yields rise, there is no basis for concluding that the absolute cost of new A-rated long-term debt will retreat significantly from current levels.[65] At a 2010 forecast long Canada yield of 4.25% and assuming that the absolute cost of long-term debt for A-rated utilities remains in the range of 6.50% to 6.75%, the A rated utility bond/long-term Canada bond yield spread will be approximately 225-250 basis points. The indicated utility equity risk premium at a long-term Canada bond yield of 4.25% and a yield spread of 225-250 basis points is approximately 6.0%. The indicated utility cost of equity before any adjustment for financing flexibility is 10.25%.

The average cost of equity based on both the single and two variable DCF-based equity risk premium approaches is 10.0%.

[63] Prior to the elimination of the FPR, the Canadian bond market was largely a domestic market. As long as there was a cap on foreign investment, pension funds limited their foreign investments primarily to equities, and allocated their bond investments to Canadian bonds, which constrained yield spreads.
[64] Utility bond yields in Canada and the U.S. have already exhibited convergence as discussed in footnote 20 above.
[65] Blue Chip *Financial Forecasts*, December 2008 anticipates that, although credit spreads with Treasury bonds will decline, the absolute yields on AAA rated U.S. corporate bonds will remain essentially flat between 2009 and 2010 and then gradually rise by approximately 50 basis points between 2010 and 2014.

B.5. Historic Utility Equity Risk Premiums

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

Over the longer-term (1956-2008),[66] the average achieved utility equity risk premium was 4.1% for Canadian electric and gas utilities in relation to total bond returns and 4.2% in relation to bond income returns respectively.[67] For U.S. electric utilities, the 1947-2008 average risk premiums were 4.2% and 4.8% (See Schedule 13). For U.S. gas utilities, the corresponding average historic equity risk premiums over the entire post-World War II period (1947-2008) were 5.5% and 6.1% respectively.

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns, as summarized for the three utility indices in the table below.

Table 9

	Utility Equity Returns	Bond Total Returns	Bond Income Returns
Canadian Utilities	12.0%	7.9%	7.8%
U.S. Electric Utilities	10.8%	6.6%	6.0%
U.S. Gas Utilities	12.1%	6.6%	6.0%

Source: Schedule 13.

[66] The longest period for which Canadian utility data are available from the TSE.
[67] Based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2008.

An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns (Schedule 14); the utility returns in both the U.S. and Canada have clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%. However, as noted in Section B.3.b(6) above and in Appendix B, the achieved bond returns (both total and income returns), particularly in Canada, are well above the levels forecast over the longer-term. The forecast long-term Canada bond yield for the longer-term is approximately 5.25%. Compared to a utility return of approximately 11.5%, the indicated utility equity risk premium is approximately 6.25%. Using the forecast 2010 long-term Canada bond yield of 4.25% and a utility risk premium of 6.25%, the indicated utility cost of equity, before adjustment for financing flexibility, is 10.5%.

B.6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility costs of equity based on the three equity risk premium methodologies are as follows:

Table 10

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.75%
DCF-Based	10.0%
Historic Utility	10.5%

The three risk premium tests indicate a utility cost of equity of approximately 9.75% before any allowance for financing flexibility.

C. DISCOUNTED CASH FLOW TEST[68]

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor,

[68] See Appendix D for a more detailed discussion.

discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows.

Although the DCF test, like the equity risk premium test, has flaws, it has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM indirectly estimates the cost of equity. In addition, the DCF model is a positive model; that is, it deals with "what is" as opposed to "what should be". The DCF model provides a widely used alternative to the CAPM; it is the principal model utilized by U.S. regulators.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. To estimate the DCF cost of equity, I utilized both a constant growth and a two-stage model.[69] In both cases, the discounted cash flow test was applied to a sample of low risk U.S. "pure-play" electric and gas distributors that are intended to serve as a proxy for NP.[70]

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is

[69] The two-stage model is a form of multiple period model; please see Appendix D for discussion of the DCF models used. The criteria for the low risk U.S. utility sample selection are described in Appendix C.
[70] Reliance on U.S. utilities was explained in the discussion of the DCF-based equity risk premium test in Section VI.B.4.

important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.)

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. Thus, in applying the DCF test, I relied solely on published forecast growth rates that are readily available to investors. In applying the constant growth model, I relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations.

In the application of the DCF test, the reliability of the earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. For the sample of low risk utilities used in the DCF test (as well as the DCF-based equity risk premium test), the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1991-March 2009 period of analysis was 5.0%. That growth rate is lower than the expected long-term nominal growth in the economy as a whole has been over the same period.[71] An expected growth rate that is close to that of the economy as a whole would not be out-of-line with the level of growth investors could reasonably expect in the relatively mature utility industries over the longer-term.

In addition, I incorporated *Value Line* forecasts of earnings growth in addition to the I/B/E/S consensus forecasts. As an independent research firm, *Value Line* has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to

[71] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1991-2009), has been 5.4% over the same period covered by the DCF-based equity risk premium test.

investors. Incorporating *Value Line* estimates of earnings growth is a means of assessing the reasonableness of the results obtains through use of the I/B/E/S consensus estimates.[72]

The mean and median *Value Line* expected long-term earnings growth rate for the utility sample were both 6.0%; the corresponding I/B/E/S forecasts were 5.7% and 5.4%. This comparison suggests no upward bias in the I/B/E/S forecasts. The constant growth models indicate a cost of equity of approximately 11.0% (Schedules 16 and 17).

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year 6 onward) to migrate to the expected long-run rate of nominal growth in the economy. The two-stage model indicates a cost of equity of approximately 10.4% (Schedule 18).

The two DCF models support a cost of equity, before adjustment for financing flexibility in the range of 10.5-11.0%.

It is important to recognize that the 10.5-11.0% DCF cost represents the return investors expect to earn on the current market value of their utility common equity investments. It is not, however, the return that investors expect the utilities to earn on the book value of their common equity. *Value Line*, which publishes its projections of utility ROEs quarterly, anticipates that the return on average common equity for the sample of benchmark U.S. utilities over the period 2012-2014 will be approximately 11.6-12.3% (Schedule 15).

[72] The British Columbia Utilities Commission found, in Order G-14-06 for Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., March 2006, "The Commission Panel is more persuaded by Ms. McShane's evidence which compares *Value Line* and I/B/E/S forecasts and finds no upward bias in the latter."

D. ALLOWANCE FOR FINANCING FLEXIBILITY[73]

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the "fairness" principle.

In the absence of an adjustment for financial flexibility, the application of a “bare-bones” cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite has averaged 2.0 times over the full business cycle (1991-2007); the corresponding average market/book ratio of the S&P 500 has been 3.1 times.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[74] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard.

The addition of an allowance for financing flexibility of 50 basis points to the “bare-bones” return on equity estimate of 9.75%-10.75% derived from both the DCF and equity risk premium tests, results in an estimate of the fair return on equity of 10.25%-11.25%.

[73] See Appendix E for a more complete discussion.
[74] Based on the DCF model; see Appendix E for calculation.

E. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard. The comparable earnings test recognizes that utility costs are measured in vintaged dollars and rates are based on accounting costs, not economic costs. In contrast, the tests for estimating the cost of attracting capital rely on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable returns standard, as well as the principle of fairness, suggests that, if competitive firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable returns standard when setting a just and reasonable return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. To illustrate, if the market value of an investment is $15 and the required return is 10%, the return, in dollars, expected by investors is $1.50. However, regulatory convention applies the market-derived return to the book value of the investment. If the book value of the investment is $10.00, application of a 10% return to the book value will result in a return, in dollars, of only $1.00. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value.[75] The comparable earnings test, however, does. It applies "apples to apples", i.e., a book value-measured return is applied to a book value-measured equity investment.

The principal issues in the application of the comparable earnings test are:[76]

- ♦ The selection of a sample of unregulated companies of reasonably comparable total risk to a Canadian utility.
- ♦ The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.

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[75] As previously noted, the 50 basis point financing flexibility adjustment is only a minimal recognition of the discrepancy.

[76] Full discussion in Appendix F.

- ♦ The need for any adjustment to the "raw" comparable earnings results if the selected unregulated companies are not of precisely equivalent risk to a utility.
- ♦ The need for a downward adjustment for the unregulated companies’ market/book ratios.

The application of the comparable earnings test first requires the selection of a sample of unregulated companies of reasonably comparable risk to a Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of a sample of unregulated companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, stock and bond ratings and betas (See Appendix F).

Since the universe of Canadian unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 27 companies.

Next, since unregulated companies’ returns on equity tend to be cyclical, the selection of an appropriate period for measuring their returns must be determined. The period selected should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be similar in terms of inflation and real economic growth. The full business cycle 1991-2007 provides an appropriate proxy for the next business cycle, as the average experienced rates of inflation and economic growth were reasonably similar to the rates projected by economists over the next business cycle. The experienced returns on equity of the sample of 27 Canadian low risk unregulated companies over this period were in the range of 12.5%-12.75% (see Appendix F and Schedule 20).

The next step is to assess whether or not there is a need to adjust the “raw” comparable earnings results to reflect the differential risk of a Canadian utility relative to the selected unregulated companies. The comparative risk data (including betas and stock and bond ratings) indicate, on balance, the unregulated Canadian companies are of modestly higher risk than the typical Canadian utility, e.g., NP. To recognize the unregulated companies' somewhat higher risk, a downward adjustment of 75-100 basis points[77] to their returns on equity was made, resulting in a comparable earnings result in the range of 11.5-11.75%.

While the focus of the comparable earnings analysis is on the Canadian sample, I also selected a sample of low risk unregulated U.S. companies to corroborate the reasonableness of the Canadian results. The selection criteria were similar to those used for the Canadian unregulated company sample. The greater breadth of the U.S. market allowed the selection of a sample of 81 companies in the same stable industries used to select the Canadian unregulated companies. The experienced returns of the U.S. unregulated companies were approximately 15.5%. (see Appendix F and Schedule 21). The comparative risk data indicate that the U.S. unregulated companies are of somewhat higher risk than the benchmark sample of U.S. utilities (see Appendix F and Schedules 19 and 21). The ROE adjusted for the U.S. unregulated companies' higher risk relative to utilities is approximately 14%. The returns of the significantly larger U.S. unregulated company sample underscore the reasonableness of the comparable earnings results for the sample of unregulated Canadian companies.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a high market/book ratio (relative to that of the overall market) could suggest returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratio of the sample of Canadian comparable unregulated companies over the 1991-2007 period was 2.1 times, virtually identical to the market/book ratio of the

[77] Based on the typical spread between Moody's BBB-rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas of the unregulated companies and the Canadian and U.S. utility samples.

S&P/TSX composite over the same period and substantially lower than the 3.1 times recorded by the S&P 500 (see Appendix F). The similar to lower average market/book ratio of the Canadian proxy sample relative to both the Canadian and U.S. equity market composites indicates no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios. As a result, a fair return on equity based on the comparable earnings test is approximately 11.5-11.75%.

F. FAIR RETURN ON EQUITY FOR NP

The results of the three tests used to estimate a fair return on equity for NP are summarized below:

Table 11

Test	Cost of Equity	Fair Return on Equity
Equity Risk Premium	9.75%	10.25%
Discounted Cash Flow	10.5-11.0%	11.0-11.5%
Comparable Earnings	N/A	11.5-11.75%

In arriving at a reasonable return for a benchmark utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. The "bare-bones" cost of attracting capital based on these two tests is approximately 9.75-10.75%. Including the allowance for financing flexibility, the indicated return on equity is 10.25-11.25%. However, the results of the comparable earnings test are also entitled to significant weight when setting a fair return. A fair ROE for NP based on all three tests is approximately 11.0%.

Appendices

Capital Structure and Fair Return on Equity

Prepared for

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May 2009

APPENDICES

A THE FAIR RETURN STANDARD

B. RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

C. DCF-BASED RISK PREMIUM TEST

D. DISCOUNTED CASH FLOW TEST

E. FINANCING FLEXIBILITY ADJUSTMENT

F. COMPARABLE EARNINGS TEST

G. QUALIFICATIONS OF KATHLEEN C. McSHANE

APPENDIX A

THE FAIR
RETURN STANDARD

Three standards for a fair return have arisen from the legal precedents for establishing a fair return, the capital attraction, financial integrity and comparable returns, or comparable investment, standard. The principal Court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923)*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

In *Northwestern*, Mr. Justice Lamont stated

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

In *Bluefield*, the criteria for a fair return were described as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

In *Hope*, Justice Douglas stated,

> By that standard the return on equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction/financial integrity standards and the comparable returns standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, *Hope* opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination. The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment.

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. For regulated utilities historic costs have been substituted for marginal or incremental costs for two reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets.

The current cost of attracting capital is measured by reference to market values. The discounted cash flow test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms).

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services; raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

Therefore, when the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value.

APPENDIX B

RISK-ADJUSTED
EQUITY MARKET RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F} \quad + \quad \boldsymbol{\beta}(\mathbf{R_M} - \mathbf{R_F}),$$

Where:

$\mathbf{R_F}$ = risk-free rate

$\boldsymbol{\beta}$ = covariability of the security with the market (M)

$\mathbf{R_M}$ = return on the market.

The model is based on restrictive assumptions, including:

a. Perfect, or efficient, markets exist where,

(1) each investor assumes he has no effect on security prices;

(2) there are no taxes or transaction costs;

(3) all assets are publicly traded and perfectly divisible;

(4) there are no constraints on short-sales; and,

(5) the same risk-free rate applies to both borrowing and lending.

b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

2. RISK-FREE RATE

a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

(1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government has been in a surplus position since 1997/1998 (eleven years), which has reduced its financing requirements. However, the demand for long-term government securities by institutions (e.g., pension funds) that match assets and liabilities has not declined. The pension funds, key purchasers of long-term government bonds, are typically buy and hold investors which means that the government bonds in their portfolios do not trade. Thus, there is the potential not only for a scarcity premium in prices due to the demand for long-term government bonds, but also potential illiquidity in the market.

(2) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term

average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, and most recently, in the wake of the subprime mortgage crisis commencing in late 2007, investors have shifted to the safe haven of government securities, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM captures the lower government bond yields, but not the increase in the equity risk premium.

(3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The need to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

(4) The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

3. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[1] The next largest sector, financial services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table B-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table B-1

	1980	2000
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2007, the energy and materials (largely mining) sectors accounted for close to 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 75% of the total market value of the composite. Despite the sharp decline in commodity prices in 2008

[1] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

and the fall-out of the sub-prime mortgage crisis, at the end of 2008, the same three sectors continued to represent close to three-quarters of the value of the S&P/TSX Composite Index.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at December 2008 demonstrates the difference.

Table B-2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.7%	8.4%
Consumer Staples	3.4%	12.9%
Energy	27.4%	13.3%
Financials	29.2%	13.3%
Health Care	0.4%	14.8%
Industrials	6.1%	11.1%
Information Technology	3.3%	15.3%
Materials	17.6%	3.0%
Telecommunication Services	6.0%	3.8%
Utilities	1.9%	4.2%

Source: *TSX Review* December 2008 and Standardandpoors.com.

Even within the remaining 25% of the Canadian market (the non-resource and non-financial sectors); there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index as compared to the largest stock in the S&P 500 at that time (General Electric) which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the Composite regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some these concerns when it overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2008 there were 220 companies in the S&P/TSX Composite Index, including 53 income trusts.

The addition of income trusts in 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. At the end of 2008, income trusts continued to be a significant component of the S&P/TSX, accounting for approximately 25% of the issues and 7% of the value of the index.

Despite the change to the income tax treatment of income trusts announced in October 2006, income trusts significantly outperformed "conventional" equities during the period for which income trust market data are readily available. The annual total return for the S&P/TSX Capped Income Trust Index over the 1998-2008 period averaged 10.8%, compared to 4.7% for the S&P/TSX Composite Index. The exclusion of income trust returns from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[2] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[3] which supported the removal of the cap.[4] The *Globe and Mail* reported that the

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[2] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.

[3] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

[4] The IFIC's report *Year 2002 in Review* stated,

removal of the foreign content cap is expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[5] The Foreign Property Rule was finally eliminated in 2005.

4. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance,* Boston: Irwin/McGraw Hill, 2006 (p. 151), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for this purpose is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[5] Rob Carrick, *Finance: Your Bottom Line*, Globeandmail.com, February 23, 2005.

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.[6]

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

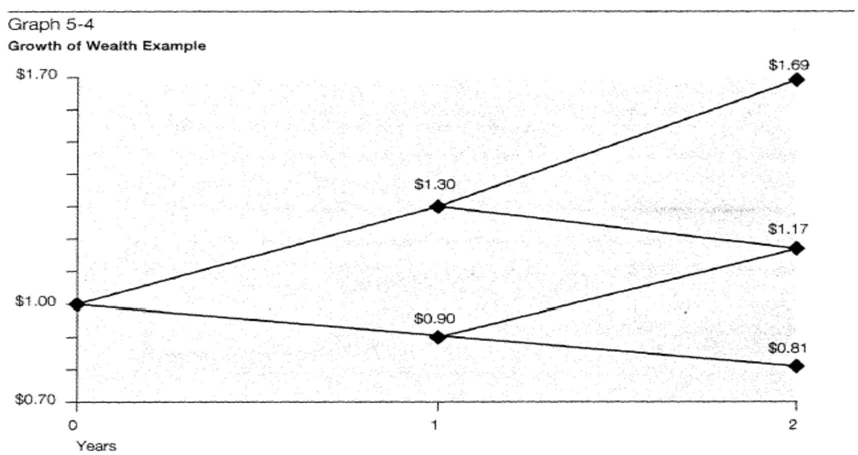
> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

[6] An illustration from Ibbotson Associates demonstrating why the arithmetic average is more appropriate than the geometric average for estimating the expected risk premium is presented on pages B11 and B12.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2008,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.



> The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)x(1-0.10)]^{1/2} - 1 = 0.082$$

> However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x $1.69)	=	$0.4225
+	(0.50 x $1.17)	=	$0.5850
+	(0.25 x $0.81)	=	$0.2025
	Total		$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \text{ x } (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1 \text{ x } (1+0.0.082)^2 = \$1.17$$

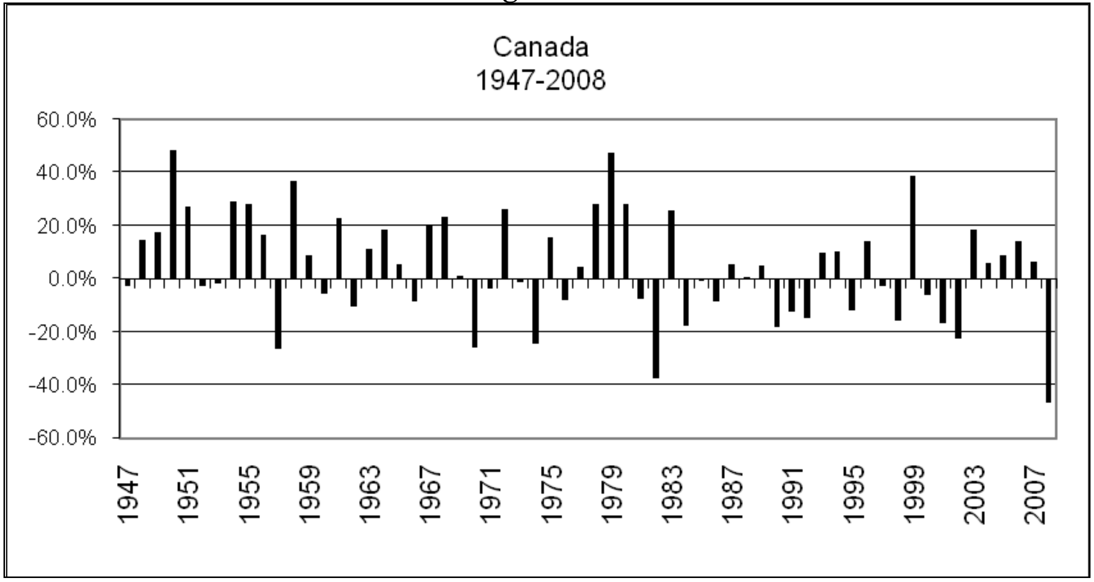
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historic annual risk premiums. The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[7]

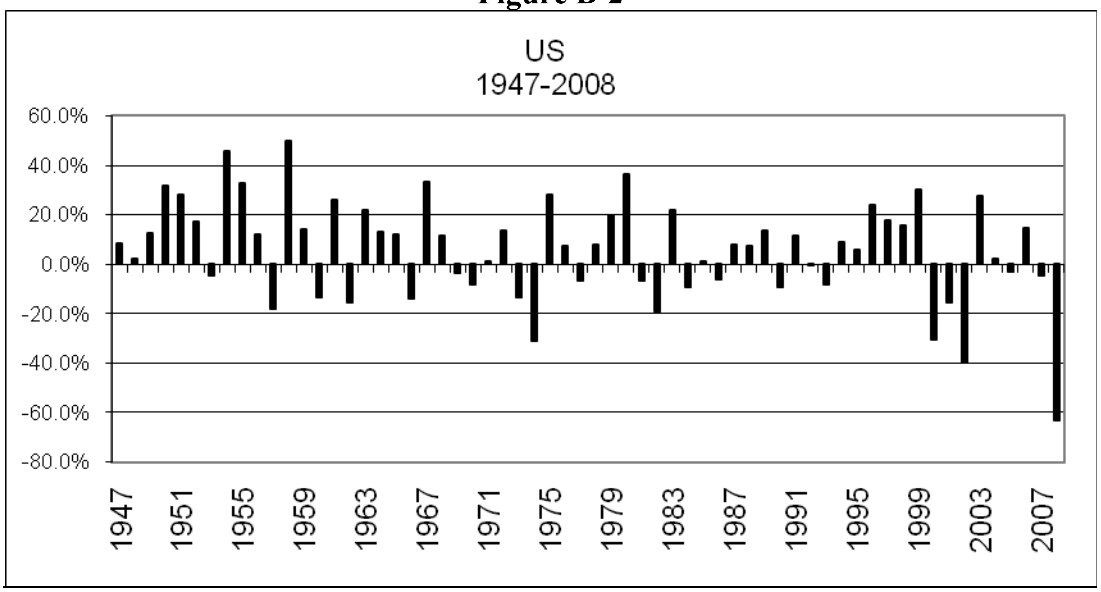
[7] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2008 is 0.06 for Canada and -0.02 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Figure B-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006*; Ibbotson *Canadian Risk Premia Over Time 2008*, *TSX Review* and Bank of Canada

Figure B-2



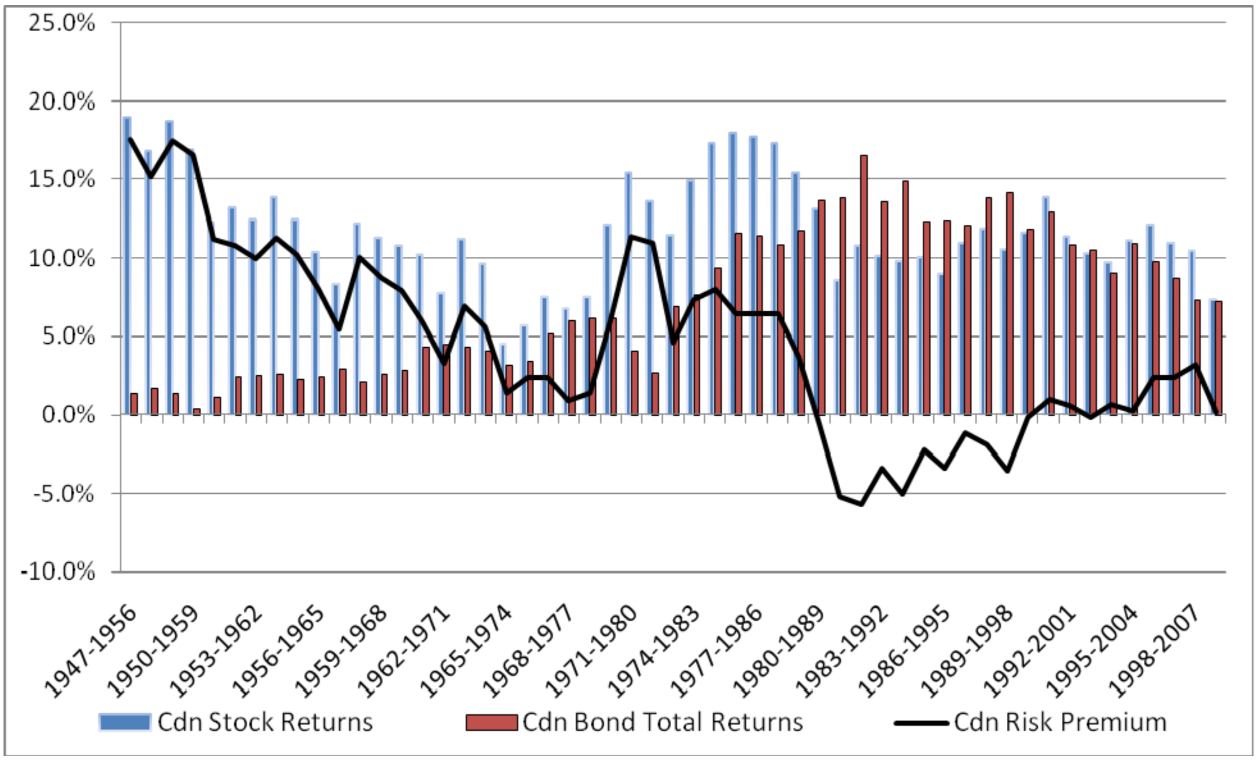
Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2009 Yearbook*, www.standardandpoors.com and the Federal Reserve

5. FUTURE vs. HISTORIC RISK PREMIUMS

a. Trends in Canadian Equity and Government Bond Returns

Figures B-3 and B-4 compare historic Canadian stock returns, long-term government bond total and income[8] returns and equity risk premiums, over rolling 10-year periods ending 1956-2008.

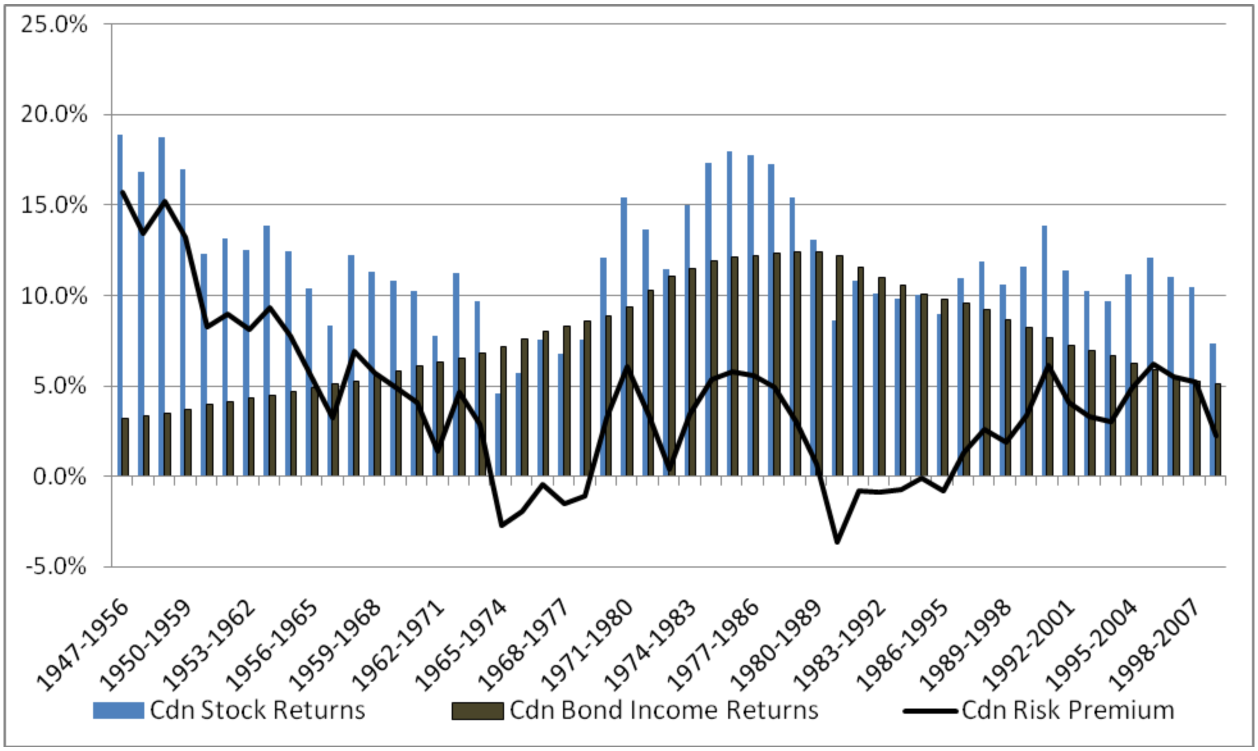
Figure B-3



Source: Schedule 9.

[8] The income return reflects only the bond coupon portion of the total bond return. The other components are the reinvestment return and the capital gain or loss. The bond coupon payment represents the riskless portion of the bond total return.

Figure B-4



Source: Schedule 9.

The rolling ten-year averages in both Figures B-3 and B-4 suggest that there has been no upward or downward trend over time in equity returns over time. On average, equity market returns in Canada have been approximately 11.5% from 1947-2008. By comparison, bond returns (both Total and Income returns) exhibited an increase throughout much of the period, before beginning to decline in the early to mid-1990s. The pattern in the bond returns results from:

- ♦ rising bond yields in the 1950s through the mid-1980s, which produced capital losses on bonds and low bond total return;

- ♦ high bond income and income returns in the 1980s, reflecting the high rates of inflation; and,

- ♦ high bond total returns in the 1990s and first half of the 2000s, reflecting the decline in long-term government bond yields, resulting in capital gains and total returns well in excess of the yields.[9]

The resulting average income and total return on long-term government bonds in Canada has been approximately 7.0% during the post-World War II period (1947-2008), well in excess of the long-term Canada bond yields which are forecast to prevail going forward.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return, based solely on the post-World War II Canadian equity market returns, is approximately 11.5%. Based on a 2010 forecast long-term Canada bond yields of 4.25%, and an expected equity market return over the long-term of 11.5%, the indicated equity market risk premium is approximately 7.25%. Based on the longer-term (2009-2019) forecast for long-term Canada bond yields of approximately 5.25%,[10] the indicated equity market risk premium is 6.25%.

b. Trends in Price/Earnings Ratios

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[11] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[12] From 11.7 times in

[9] The bond yield is, in fact, an estimate of the expected return.
[10] Consensus Economics, *Consensus Forecasts*, April 2009 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2009 to 2019. The average spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.
[11] Price to trailing earnings.
[12] The average from 1947-1988 was 13 times.

1988, the P/E ratio gradually rose, peaking at over 46 times in late 2001. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[13] By mid-2006, the P/E ratio had fallen to 17 times; in early 2009, with the sell-off in the market which commenced in mid-2007, it was 13 times (based on estimated 2009 operating earnings), compared to the long-term (1936-2008) average of approximately 16 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1936 and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.3% from 1936-1988. The corresponding average return from 1936-2008 was 11.8%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually <u>lower</u> over the entire 1936-2008 period than over the 1936-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.2% over the entire 1947-2008 period. Stated differently, the increase in P/E ratios during the 1990s has not resulted in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable. Relative to the consensus forecast yield for 30-year Treasury bonds for 2010 of

[13] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

approximately 4.25% and for the longer term of approximately 5.4%,[14] the risk premium would be approximately 6.5-7.75%.

My review of equity returns in Canada indicates similar results. The 1936-1988 arithmetic average return for the Canadian equity market was 11.8%, identical to the average U.S. equity market return for the same period, and higher than the average 1936-2008 return of 11.0%. Similarly, the 1947-1988 return of 12.9% is higher than the 1947-2008 return of 11.6%. There is no indication that rising P/E ratios during the bull market of the 1990s have produced returns that are unsustainable going forward.

c. Equity Market Risk Premium

The analysis of stock and bond returns in Canada and the U.S. during the post World War II period reveals no upward or downward trend in market equity returns. Nevertheless, the achieved risk premiums have declined. The arithmetic average achieved risk premium in Canada (in relation to bond total returns) from 1947-1988 was 7.7%; in the U.S., it was 8.4%. By comparison, the corresponding 1947-2008 achieved risk premiums (in relation to the total returns on bonds) were 4.6% and 5.6% for Canada and the U.S. respectively. An analysis of the data shows that high bond returns have been the principal reason for the decline in experienced risk premiums, not a downward trend in equity returns. The average bond total return (income plus capital appreciation) in Canada from 1989-2008 was 10.7%.

Over the entire 1947-2008 period, the average income total return on long-term Canada bonds was approximately 7.0%. With long-term Canada bond yields at historically low levels (approximately 3.75% at mid-April 2009), and more likely to increase rather than decrease further, the 1947-2008 average bond returns of approximately 7.0% overstate the forward-looking expected bond return indicated by current and forecast 30-year Canada bond yields. A reasonable expected value of the long-term Canada bond return

[14] Blue Chip *Financial Forecasts*, December 1, 2008 and April 1, 2009.

for the purpose of estimating the forward-looking equity market risk premium is the forecast long-term Canada bond yields, rather than the historic average bond returns.

Thus, a reasonable estimate of the forward-looking equity market risk premium is approximately 6.75%, based on historic equity market returns in Canada and the U.S. in the range of 11.0% to 12.0%[15] and a risk-free rate of 4.25% (2010 forecast of 30-year Canada bond yield) to 5.25% (forecast of 30-year Canada bond yield over the longer term).

6. RELATIVE RISK ADJUSTMENT

a. Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

(1) The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

(2) The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

(3) The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market)[16] are a good measure of the relative return requirement.

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[15] Over the three-month period, January 2009-March 2009, the average dividend yield on the S&P/TSX was 2.6%. The expected long-term growth rate for the index based on available analysts' forecasts for the companies in the Composite, is 9.9%, indicating an expected return (based on a discounted cash flow approach) of approximately 12.8%.

[16] The beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

(4) Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

Fama and French in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

Fama and French have developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM.[17]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.

[17] The additional factors are size and book to market.

> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[18]

b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

[18] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

The analysis showed the following:

Table B-3

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 11, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table B-3 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2008, the longest period for which data for the new Composite and its sector components are available; (b) 1988-1997,[19] and (c) the most recent 10-year period ending 2008.

[19] The use of this sub-period was intended to ensure elimination of the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.

That analysis showed the following:

Table B-4

Returns Measured Over:	Coefficient on Beta	R^2
1988-2008	-.047	26%
1988-1997	-.017	1%
1999-2008	-.084	32%

Source: Schedule 11, page 2 of 3.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship. The results strongly suggest that, at a minimum, adjusted betas, rather than "raw" betas, should be relied upon in the application of the CAPM. Adjusting betas toward the equity market mean beta of 1.0 takes account of the empirically observed tendency of stocks with "raw" betas below 1.0 to achieve returns higher than implied by the theoretical single variable CAPM and vice versa.

APPENDIX C

DCF-BASED RISK PREMIUM TEST

1. SELECTION OF LOW RISK BENCHMARK U.S. UTILITIES

For the estimation of the benchmark return, a sample of low risk U.S. utilities was selected, comprised of all electric utilities and gas distributors satisfying the following criteria:

a. Classified by *Value Line* as a gas distributor or an electric utility;

b. *Value Line* Safety Rank of “2” or better;

c. Standard & Poor’s business risk profile of “Excellent”;

d. Standard & Poor’s debt rating of A- or higher;

e. Not presently being acquired; and,

f. Consistent history of analysts’ forecasts.

The 13 utilities that met these criteria are listed on Schedule 15.

2. CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the 13 utilities in the sample over the period 1991-March 2009. The monthly DCF cost for each utility was estimated as the sum of the utilities' I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S mean earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 12). The monthly sample average ERPs were used to estimate the regression equations found on Schedule 12, page 2 of 2.

APPENDIX D

DISCOUNTED CASH FLOW TEST

1. DCF MODELS

a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[20]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

[20] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Two-Stage Model

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1 Growth), but, in the longer-term (from Year 6 onward) to migrate to the expected long-run rate of growth in the economy (GDP Growth). All industries go through various stages in their life cycle. Utilities are considered to be the quintessential mature industry. Mature industries are those whose growth parallels that of the overall economy.

The use of forecast GDP growth as the long-term growth component is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth for conventional corporations in its standard DCF models for gas and oil pipelines.

Using the two-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor.

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

Cash flows from Year 6 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

3. SELECTION OF PROXY BENCHMARK UTILITIES

The same sample of benchmark utilities was used as for the DCF-based risk premium test. The selection criteria for these low risk utilities are described in Appendix C.

4. INVESTOR GROWTH EXPECTATIONS

The application of the constant growth model relies principally on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S. The application of the two-stage model relies upon the I/B/E/S consensus earnings forecasts as the estimate of investor growth expectations during Stage 1. In the second stage, the investor growth expectations are proxied by the expected nominal long-run rate of growth in the economy (GDP) based on the consensus of economists' long-term forecasts (published twice annually) found in *Blue Chip Financial Forecasts* (December 1, 2008). The consensus forecast rate of growth in the long-term (2010-2019) is 5.0%.

5. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk gas and electric utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of March 31, 2009 as D_o; and,

(2) the average of the high and low monthly prices for the period January 1, 2009 to March 31, 2009 as P_o.

For the expected growth rates, the March 2009 I/B/E/S consensus (mean) earnings growth forecasts and the most recent *Value Line* forecasts of earnings growth[21] were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield.

Table D-1 below summarizes the results of the constant growth model.

Table D-1

Earnings Growth Forecast	DCF Cost of Equity	
	Mean	**Median**
I/B/E/S	11.0%	10.9%
Value Line	11.3%	11.0%

Source: Schedules 16 and 17.

[21] Estimates issued in February and March 2009.

b. Two-Stage Model

The two-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), and forecast growth in the economy thereafter (Stage 2). The consensus long-run (2010-2019) expected nominal rate of growth in GDP, as noted above, is 5.0%.

The two-stage DCF model estimates of the cost of equity for the benchmark low risk U.S. utility sample (Schedule 18) are as follows:

Mean	10.3%
Median	10.5%

c. Results of the Constant Growth and Two-Stage Models

The results of the two models indicate a required "bare-bones" return on equity of approximately 10.4% (two-stage model) to 11.0% (constant growth model).

APPENDIX E

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is "bare-bones" in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[22]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

[22] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000 and took out a mortgage for the full amount. My home is currently worth $250,000 and my mortgage is now $85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $165,000 (market value of $250,000 less the $85,000 unpaid mortgage), not the "book value" of the equity in my home of $15,000, which reflects the original purchase price less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, application of an unadjusted market-derived cost of equity to the book value capital structure fails to recognize the higher financial risk and the higher cost of equity implied by the book value capital structures.

Two approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity. The first approach is based on the theory that the overall cost of capital does not change materially over a relatively broad range of capital structures. The second approach is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense.[23]

Schedules 24 and 25 provide the formulas and inputs for estimating the change in the cost of equity under each of the two approaches. The schedules show that a recognition of the difference in financial risk between the market value and book value capital structures of the

[23] The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

publicly-traded Canadian utilities and the low risk U.S. utilities results in an increase in the cost of equity of approximately 100 basis points. A minimal recognition of the higher financial risk in the book value capital structures supports a financing flexibility adjustment of no less than 50 basis points.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[24]

The financing flexibility allowance should be, at a minimum, 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable earnings standard.

[24] The financing flexibility allowance is estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x “bare-bones” Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a dividend payout ratio of 65% and a cost of equity of 10.5%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \text{ x } 10.5\%}{1 + [.35\,(1.075 - 1.0)]}$$

$$\text{ROE} = 11.0\%$$

The difference of 50 basis points between the ROE and the “bare-bones” cost of equity is the financing flexibility allowance.

APPENDIX F

COMPARABLE EARNINGS TEST

1. SELECTION OF CANADIAN UNREGULATED COMPANIES

The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonably comparable investment risk to utilities.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[25] The resulting universe contained 490 firms. Companies were removed which:

- Had 2007 equity less than $100 million,
- Had missing or negative common equity during 1991-2007,
- Were income trusts,
- Had less than five years of market data,
- Paid no dividends in any year 2004-2008,
- Traded fewer than 5% of their outstanding shares in 2007,

[25] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

- Had stock ranked “higher risk” or “speculative by the Canadian Business Service (CBS)
- Had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor’s, or for which none of the agencies report a rating,
- Had average five-year “raw” betas ending December 2007 and December 2008 in excess of 1.0.

The final sample of low risk Canadian unregulated companies is comprised of 27 companies (Schedule 19).

2. TIME PERIOD FOR MEASURING RETURNS

Since unregulated companies’ returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1991-2007 constitutes a full business cycle including the recession of 1991-1992. Over the period 1991-2007, the experienced returns on equity of the sample of 27 low risk unregulated Canadian companies were as follows.

Table F-1

ROEs for Low Risk Canadian Unregulated Companies (1991-2007)	
Average	12.5%
Median	12.7%
Average of Annual Medians	12.8%

Source: Schedule 20.

Based on these data, the ROEs for the low risk Canadian unregulated companies are in the approximate range of 12.5-12.75%.

The average nominal economic growth for Canada during the 1991-2007 business cycle was 4.9%, compared to the consensus forecast for real growth of 2.7%, and for inflation (CPI) of approximately 2.1% for the period (2010-2019)[26], which suggests nominal long-term GDP growth of approximately 4.8%. Since nominal growth is expected to be virtually identical to the experienced rate during the past full business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

3. RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian unregulated companies relative to Canadian utilities, comparisons of the various risk measures indicate that they are in a similar risk class. The median CBS stock rating for the unregulated companies is "Very Conservative", the same as that of the investor-owned Canadian utilities with publicly-traded stock. The median S&P and DBRS debt ratings for the unregulated companies are BBB and BBB/BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 3 and 19). The median adjusted beta for the unregulated companies averaged 0.71 for the two five-year periods ending December 2007 and 2008 (see Schedule 19), compared to the adjusted betas for Canadian utilities over the same time period of 0.59 (Schedule 11).

The estimate of a normal cycle average level of returns for low risk Canadian unregulated companies is in the approximate range of 12.5-12.75%. The comparative risk data indicate, on balance, the Canadian unregulated companies are somewhat riskier than utilities. The somewhat higher risk of the unregulated companies relative to the typical Canadian utility requires a

[26] Consensus Economics, *Consensus Forecasts*, April 2009.

modest downward adjustment. A downward adjustment of 75-100 basis points[27] reduces the ROE to a range of 11.5-11.75%.

4. U.S. UNREGULATED COMPANY SAMPLE

To ensure a sample of adequate size to provide reliable results, an additional sample of U.S. unregulated companies was selected to corroborate the reasonableness of the Canadian unregulated company results.

The U.S. unregulated sample was selected as follows: The initial universe consisted of all companies actively traded in the U.S. from S&P's Research Insight database in Global Industry Classification Standard (GICS) sectors 20-30. The resulting universe contained 2,585 companies. Companies were removed which:

- Are not incorporated in the U.S.
- Had 2007 equity less than $100 million.
- Had missing or negative common equity during 1991-2007.
- Had less than five years of market data.
- Paid no dividends in any year 2004-2008.
- Traded fewer than 5% of their outstanding shares in 2007.
- Had an S&P rating below BBB-.
- Had a *Value Line* Rank of "4" or "5".
- Had a *Value* Line beta of 1.0 or higher
- Had 1996-2007 returns outside one standard deviation of the sample average

The returns for the sample of 81 U.S. companies are summarized in Table F-2 below.

[27] Based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A rated utility bond yields and the relative betas of the unregulated companies and the Canadian and U.S. utility samples.

Table F-2

ROEs for Low Risk U.S. Unregulated Companies (1991-2007)	
Average:	15.9%
Median	14.9%
Average of Annual Medians:	15.7%

Source: Schedule 21.

The sample of unregulated U.S. companies has the following risk measures, compared to the benchmark sample of U.S. utilities.

Table F-3

	Unregulated U.S, Companies		**Benchmark Sample of U.S. Utilities**	
	Median	Mean	Median	Mean
S&P Debt Ratings	A-	A-	A	A
Value Line Risk Measures:				
Safety	3	2	1	1
Beta	0.80	0.80	0.65	0.67

Source: Schedules 15 and 21

The comparative risk data indicate that the U.S. unregulated companies are of somewhat lower risk than the benchmark sample of U.S. utilities. Using the relative betas of the unregulated U.S. companies and the utilities to adjust for the unregulated companies' higher risk, the indicated return on equity is approximately 14%. Used as a check on the returns on equity of the sample of unregulated Canadian firms, the ROEs of the significantly larger U.S. sample underscore the reasonableness of the comparable earnings results for the sample of Canadian unregulated companies.

5. MARKET/BOOK RATIOS

The argument that a downward adjustment to the comparable earnings test results for market/book ratios has been made on the following bases:

a. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.

b. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

Both of these arguments are without merit. With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the "Q Ratio", a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.[28] Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the "Q Ratio" (market value/replacement cost) should trend toward 1.0.

The "Q Ratio" has since gained stature as an investment tool,[29] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

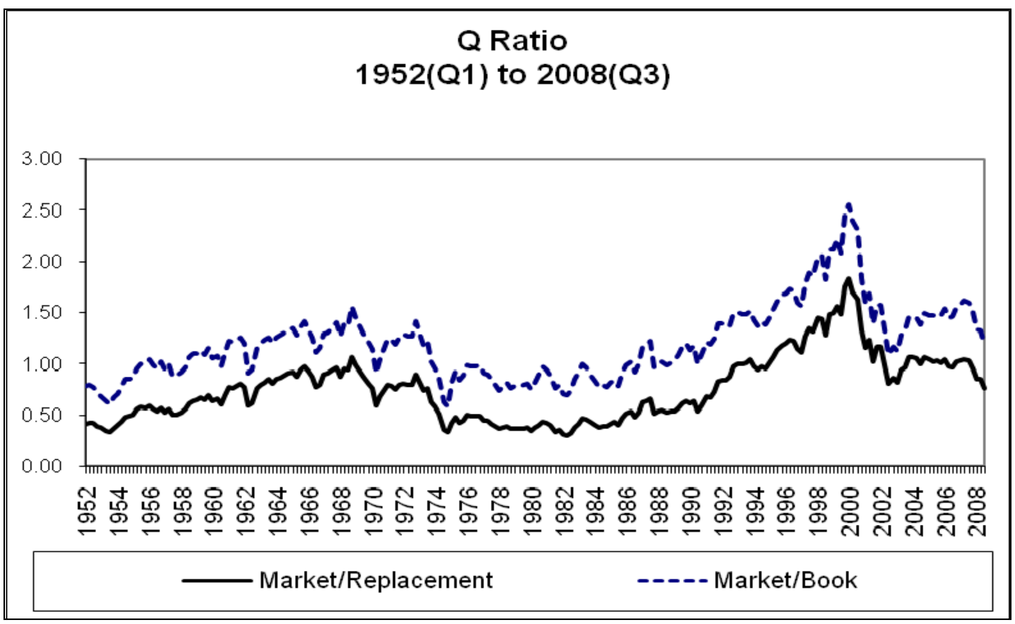
> Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin's work.
>
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. <u>While the Q ratio – as Tobin's Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today</u>. [emphasis added]

[28] The general idea had been expressed decades earlier by the economist John Keynes.
[29] The Federal Reserve Board tracks the "Q Ratio" of the U.S. equity market. It was the level of the "Q Ratio", along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

As indicated in Figure F-1 below, market/replacement cost ratios, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations[30] has averaged approximately 45% lower than the market/book ratio over the business cycle 1991-2007.

Figure F-1

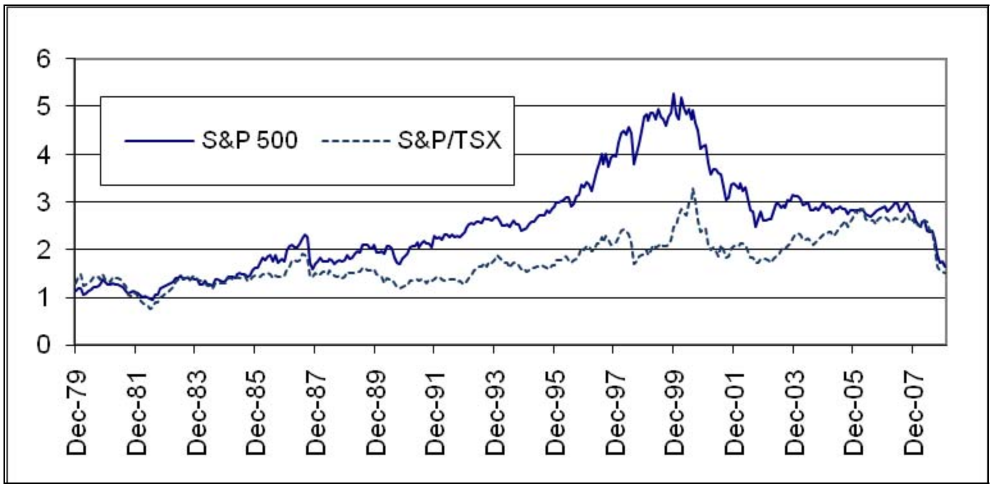


Source: US Federal Reserve Flow of Funds (B102).

[30] Based on non-farm, non-financial corporate businesses.

To test the potential for market power in the achieved returns of the sample of low risk unregulated Canadian firms used in the comparable earnings test, their market/book ratios were compared to those of Canadian and U.S. equity market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2008.

Figure F-2



Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.8 times from 1980-2008, and approximately 2.0 times from 1991-2007, the period over which the comparable earnings test was conducted. Based on almost three decades of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.8 times, not 1.0 times. For the S&P 500, the market/book ratios were approximately 2.5 and 3.1 times, respectively, over the same two periods. Over the period 1991-2007 the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times, approximately equal to the average for the S&P/TSX Composite and considerably lower than the market/book ratio of the S&P 500. The similar to lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian and U.S. equity market composites permit the inference that the sample average returns are not characterized by market power. Thus, the comparable earnings results do not warrant an adjustment for market/book ratios.

APPENDIX G

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

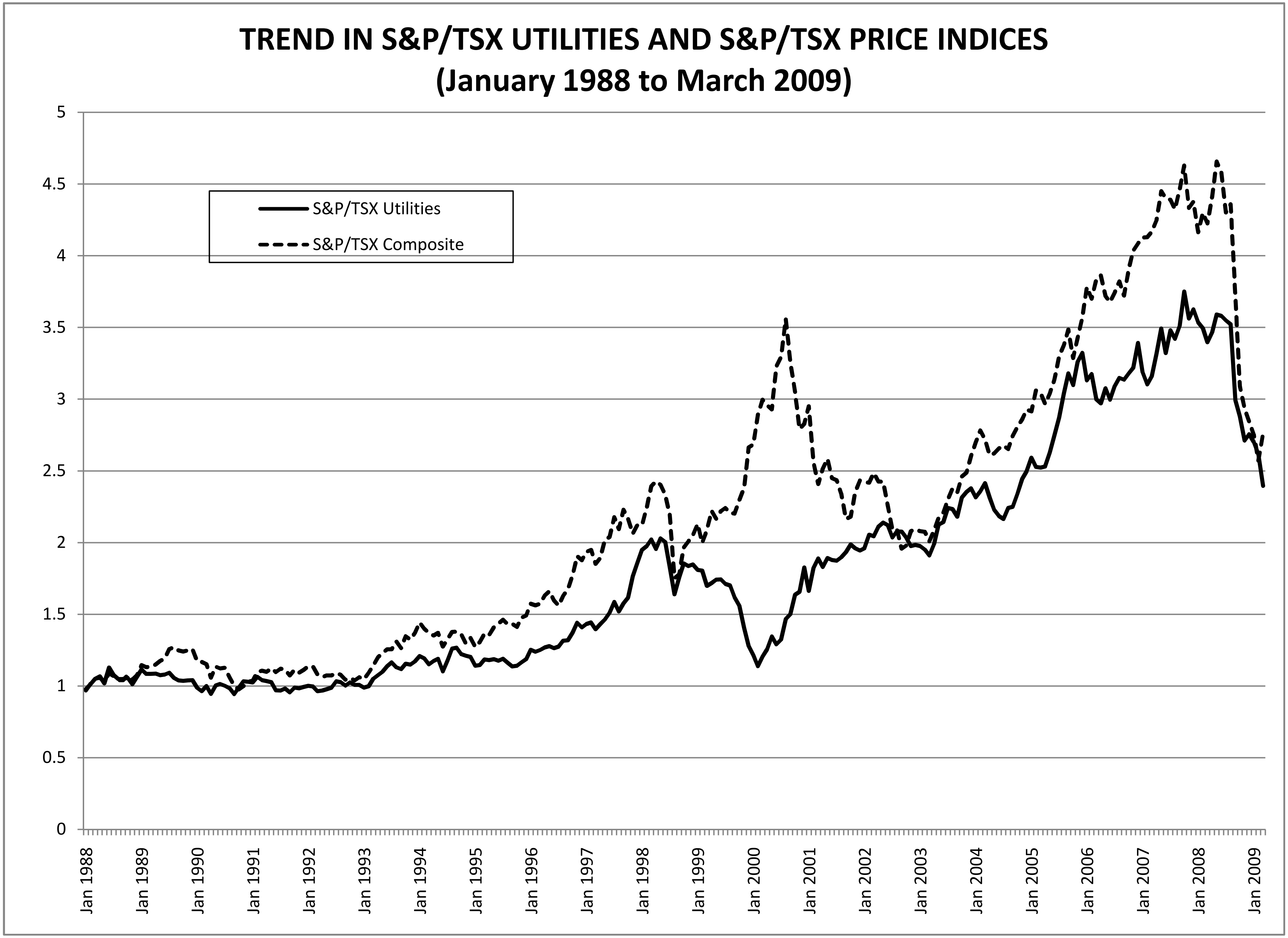
Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004

Gas Company of Hawaii	2000, 2008
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997

Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984


TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
(January 1988 to March 2009)
S&P/TSX Utilities
S&P/TSX Composite
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
Jan 1988
Jan 1989
Jan 1990
Jan 1991
Jan 1992
Jan 1993
Jan 1994
Jan 1995
Jan 1996
Jan 1997
Jan 1998
Jan 1999
Jan 2000
Jan 2001
Jan 2002
Jan 2003
Jan 2004
Jan 2005
Jan 2006
Jan 2007
Jan 2008
Jan 2009

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELD
(Percent Per Annum)

Year	Government Securities: T-Bills Canadian	T-Bills U.S. [1/]	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. [2/]	Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [4/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Annual												
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44	9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28	9.36	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01	1.33	8.64	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	1.22	7.59	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	1.12	8.30	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	0.88	7.89	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	0.63	7.75	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	0.53	7.60	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	0.79	7.04	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	1.20	7.62	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.02	1.31	8.24	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.25	1.48	7.73	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.22	1.55	7.35	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.78	1.46	6.54	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.28	1.17	6.14	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.53	1.16	5.62	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.47	1.21	6.06	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.61	1.31	6.06	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.41	2.37	6.54	0.94

[1/] Rates on new issues.
[2/] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3/] Terms to maturity of l0 years or more.
[4/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov
www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: T-BILLS Canadian	Government Securities: T-BILLS U.S. [1]	Government Securities: 10 Year Canadian	Government Securities: 10 Year U.S.	Government Securities: Long-Term Canadian	Government Securities: Long-Term U.S. [2]	Government Securities: Canada Bonds Over 10 Years [3]	Government Securities: Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [5]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	6.17	1.08	6.06	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.48	1.19	6.45	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.37	1.23	6.11	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	6.09	1.17	5.95	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.86	1.13	5.72	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.59	1.21	5.43	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.32	1.12	5.49	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.36	1.17	5.82	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.43	1.20	5.92	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.75	1.21	6.41	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.45	1.23	6.09	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.27	1.20	5.82	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.36	1.19	5.92	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.61	1.25	6.08	0.92
	q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.79	1.34	6.19	0.97
	q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.68	1.47	6.05	1.02
2008	q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.75	1.68	6.16	0.99
	q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.99	1.89	6.30	0.99
	q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.33	2.21	6.58	0.95
	q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.56	3.69	7.13	0.82
2009	q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.28	3.60	6.44	0.80
2006	Jan	3.51	4.47	4.17	4.53	4.26	4.69	4.26	1.53	5.43	1.17	5.84	0.88
	Feb	3.74	4.62	4.12	4.55	4.17	4.51	4.17	1.47	5.37	1.20	5.77	0.88
	Mar	3.86	4.61	4.26	4.86	4.26	4.89	4.32	1.58	5.49	1.23	6.14	0.86
	Apr	4.04	4.65	4.51	5.07	4.52	5.17	4.57	1.72	5.70	1.18	6.37	0.89
	May	4.18	4.86	4.45	5.12	4.50	5.21	4.51	1.83	5.68	1.18	6.43	0.91
	Jun	4.30	5.01	4.58	5.15	4.61	5.19	4.63	1.88	5.86	1.25	6.43	0.90
	Jul	4.15	5.10	4.31	4.99	4.37	5.07	4.39	1.73	5.62	1.25	6.29	0.88
	Aug	4.12	5.02	4.11	4.74	4.19	4.88	4.20	1.62	5.42	1.23	6.07	0.90
	Sep	4.16	4.89	3.99	4.64	4.08	4.77	4.09	1.67	5.30	1.22	5.90	0.89
	Oct	4.17	5.08	4.02	4.61	4.08	4.72	4.10	1.69	5.28	1.20	5.84	0.89
	Nov	4.17	5.03	3.90	4.46	3.99	4.56	4.00	1.60	5.18	1.19	5.68	0.88
	Dec	4.15	5.02	4.08	4.71	4.14	4.81	4.15	1.75	5.34	1.20	5.95	0.86
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.41	1.19	6.01	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.28	1.19	5.78	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.39	1.19	5.97	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.45	1.26	5.90	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.62	1.24	6.10	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.75	1.26	6.24	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07	5.78	1.33	6.18	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14	5.76	1.30	6.17	0.95
	Sep	3.96	3.82	4.34	4.59	4.44	4.83	4.44	2.07	5.83	1.39	6.22	1.01
	Oct	3.96	3.94	4.31	4.48	4.38	4.74	4.39	2.05	5.73	1.35	6.07	1.06
	Nov	3.91	3.15	3.98	3.97	4.16	4.40	4.15	2.07	5.69	1.53	6.00	1.00
	Dec	3.82	3.36	3.99	4.04	4.10	4.45	4.10	1.91	5.62	1.52	6.07	1.01
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.81	1.63	6.07	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.73	1.64	6.22	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.71	1.77	6.20	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.97	1.89	6.22	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.98	1.85	6.36	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	6.02	1.94	6.32	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	6.08	1.98	6.44	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.25	2.24	6.32	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.65	2.42	6.98	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.86	3.58	8.01	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.47	3.57	7.18	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.36	3.91	6.20	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.57	3.80	6.52	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.26	3.56	6.38	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	7.01	3.44	6.41	0.79

[1] Rates on new issues.
[2] 20-year constant maturities for 1974-1978; 30-year maturities, 1978-January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3] Terms to maturity of l0 years or more.
[4] Series discontinued June 2007.
[5] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000;
a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov
RBC Capital Markets, www.ustreas.gov

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada					United States				
		Gross Domestic Product			GDP	Consumer	Gross Domestic Product			Implicit	Consumer
		Constant	Current	Industrial	Deflator	Price	Constant	Current	Industrial	Price	Price
Year		Dollars	Dollars	Production	Index	Index	Dollars	Dollars	Production	Index	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(l0)
1989		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.2	104.8	101.9	105.8	101.0	103.9	105.4
1991		98.1	104.2	93.5	106.2	110.7	101.7	109.3	99.5	107.5	109.8
1992		99.0	106.5	94.5	107.6	112.3	105.1	115.6	102.4	110.0	113.2
1993		101.3	110.6	98.8	109.2	114.4	107.9	121.4	105.8	112.5	116.5
1994		106.1	117.2	105.1	110.4	114.6	112.2	129.0	111.6	114.9	119.5
1995		109.1	122.7	109.9	112.9	117.1	115.0	134.9	117.2	117.2	122.9
1996		110.9	126.8	111.8	114.7	118.9	119.3	142.5	122.2	119.5	126.5
1997		115.6	133.5	118.0	116.1	120.8	124.7	151.4	131.1	121.5	129.5
1998		120.3	139.2	122.2	115.6	122.0	129.9	159.5	139.1	122.8	131.5
1999		127.0	149.4	129.8	117.6	124.2	135.7	169.0	145.6	124.6	134.4
2000		133.6	163.5	139.6	122.5	127.5	140.6	179.0	152.2	127.3	138.9
2001		136.0	168.5	134.6	123.9	130.8	141.7	184.7	146.9	130.4	142.8
2002		140.0	175.3	137.5	125.2	133.7	143.9	190.9	144.8	132.6	145.1
2003		142.6	184.4	137.7	129.4	137.4	147.6	199.9	146.6	135.4	148.4
2004		147.0	196.3	139.8	133.5	139.9	152.9	213.1	150.2	139.3	152.3
2005		151.3	208.7	142.0	138.0	143.0	157.4	226.5	155.2	143.9	157.5
2006		156.0	220.5	142.3	141.4	145.9	161.8	240.3	158.6	148.5	162.6
2007		160.2	233.5	142.6	145.8	149.0	165.1	251.8	161.3	152.5	167.2
2008		160.9	243.6	136.7	151.4	152.6	167.2	260.4	158.5	155.8	173.6
2004	1Q	144.7	190.5	139.2	131.7	138.5	151.0	208.0	148.8	137.7	150.2
	2Q	146.4	195.4	139.7	133.5	140.0	152.3	211.7	149.5	139.0	152.4
	3Q	148.0	198.5	139.9	134.2	140.3	153.7	214.8	150.2	139.8	152.9
	4Q	149.0	200.6	140.5	134.7	140.9	154.6	217.9	152.4	140.9	153.8
2005	1Q	149.3	202.5	140.5	135.7	141.4	155.8	221.6	154.4	142.3	154.8
	2Q	150.4	205.5	141.3	136.7	142.7	156.8	224.2	155.1	143.0	156.9
	3Q	151.9	211.1	142.5	139.1	144.0	158.3	228.6	155.0	144.4	158.8
	4Q	153.5	215.6	143.7	140.6	144.1	158.8	231.5	156.4	145.8	159.6
2006	1Q	155.1	217.8	143.7	140.4	144.8	160.7	236.3	157.6	147.1	160.4
	2Q	155.7	219.7	142.2	141.2	146.4	161.7	239.5	158.6	148.1	163.1
	3Q	156.1	221.7	141.9	142.1	146.5	162.1	241.6	159.4	149.1	164.1
	4Q	157.0	223.0	141.2	142.1	146.0	162.7	243.8	159.0	149.9	162.7
2007	1Q	158.5	228.6	142.6	144.3	147.4	162.7	246.4	159.6	151.4	164.3
	2Q	160.0	233.6	143.6	146.1	149.6	164.6	250.5	160.8	152.2	167.5
	3Q	161.0	234.4	143.1	145.7	149.6	166.5	254.4	162.3	152.8	167.9
	4Q	161.3	237.2	140.9	147.1	149.5	166.5	255.8	162.4	153.7	169.1
2008	1Q	160.9	240.1	138.4	149.2	150.0	166.8	258.0	162.6	154.7	171.0
	2Q	161.2	246.3	137.3	152.8	153.1	168.0	260.6	161.2	155.2	174.8
	3Q	161.5	248.5	137.4	153.8	154.7	167.8	262.8	157.5	156.7	176.8
	4Q	160.1	239.7	133.5	149.7	152.4	166.1	260.1	152.7	156.6	171.8

Note: Data are based on Chain Weighted Indexes.

Source: www.cansim2.statcan.ca, www.bea.gov , www.federalreserve.gov

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures	A(low)		BBB+	
EPCOR Utilities Inc	Senior Unsecured	A(low)		BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	A-	Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A+	
Hydro One	Senior Unsecured	A(high)	Aa3	A+	
Hydro Ottawa Holding Inc.	Senior Unsecured	A(low)		A	
London Hydro	Issuer			A	
Maritime Electric	Senior Secured			A	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A	
Veridian	Issuer	A			
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	
	Senior Unsecured	A	A3	A	
Terasen Gas (Vancouver Is.)	Senior Unsecured		A3		
Union Gas Limited	Senior Unsecured	A		BBB+	
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A3	A-	Very conservative
Trans Quebec & Maritimes	Senior Unsecured	A(low)		BBB+	
TransCanada PipeLines	Senior Unsecured	A	A3	A-	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB+	
Medians					
Electric T&D		**A**	**Baa1**	**A**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**A-**	**Very conservative**
All Electric		**A(low)**	**Baa1**	**A**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
Pipelines		**A**	**A3**	**A-**	**Very conservative**
All Companies		**A**	**A3**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: www.dbrs.com, www.moodys.com, Standard & Poor's, *The Blue Book of CBS Stock Reports.*

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2008)

	Long-Term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
Altalink LP	61.7%	0.0%	0.0%	38.3%
CU Inc	56.6%	0.0%	5.2%	38.3%
Enersource 4/	57.5%	0.0%	0.0%	42.5%
ENMAX Corp.	37.3%	4.6%	0.0%	58.1%
EPCOR Utilities Inc.	50.3%	2.6%	2.3%	44.8%
FortisAlberta	60.0%	0.5%	0.0%	39.4%
FortisBC	59.1%	0.0%	0.0%	40.9%
Hamilton Utilities 4/	35.4%	0.0%	0.0%	64.6%
Hydro One Inc.	54.5%	0.0%	2.9%	42.6%
Hydro Ottawa Holding Inc. 4/	43.8%	4.3%	0.0%	51.9%
London Hydro 4/	36.5%	0.0%	0.0%	63.5%
Maritime Electric	53.6%	6.2%	0.0%	40.2%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%
Nova Scotia Power	54.3%	0.8%	4.7%	40.1%
Toronto Hydro	55.2%	0.0%	0.0%	44.8%
Veridian 4/	40.4%	0.0%	0.0%	59.6%
Gas Distributors				
Enbridge Gas Distribution	44.2%	18.1%	1.9%	35.8%
Gaz Metro	64.0%	2.0%	0.0%	34.0%
Pacific Northern Gas	45.6%	1.8%	3.0%	49.6%
Terasen Gas	55.7%	9.5%	0.0%	34.8%
Terasen Gas (Vancouver Is.)	46.3%	18.2%	0.0%	35.5%
Union Gas	56.1%	8.1%	2.6%	33.2%
Pipelines				
Enbridge Pipelines	52.7%	7.0%	0.0%	40.4%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%
Trans Quebec & Maritimes 4/	69.8%	0.0%	0.0%	30.2%
TransCanada Pipelines	54.1%	5.0%	1.2%	39.7%
Westcoast Energy	52.6%	1.2%	4.9%	41.3%
Medians				
Electric T&D	**53.4%**	**0.0%**	**0.0%**	**45.5%**
Electric Integrated	**54.3%**	**0.8%**	**2.3%**	**40.2%**
All Electric	**54.0%**	**0.0%**	**0.0%**	**43.7%**
Gas Distributors	**51.0%**	**8.8%**	**1.0%**	**35.2%**
Pipelines	**54.1%**	**1.2%**	**0.0%**	**39.7%**
All Companies	**54.1%**	**0.8%**	**0.0%**	**40.4%**

1/ Includes current portion of long-term debt and preferred securities classified as debt.
2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities .
3/ Includes minority interest in common shares of subsidiary companies.
4/ 2007 data.

Source: Annual Reports to Shareholders

FINANCIAL METRICS
FOR CANADIAN UTILITIES WITH RATED DEBT
2005-2007

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.9	12.6	3.1
CU Inc.	2.5	17.1	3.4
Enersource	2.2	14.9	3.2
ENMAX Corp.	8.2	18.0	3.9
EPCOR Utilities Inc.	2.8	20.3	3.6
FortisAlberta Inc.	2.2	14.3	4.2
FortisBC Inc.	2.1	10.4	2.7
Hamilton Utilities	3.2	32.2	4.9
Hydro One Inc.	2.8	14.5	3.4
Hydro Ottawa Holding Inc.	3.5	22.3	5.3
London Hydro	2.9	20.9	4.0
Maritime Electric	2.7	13.5	2.8
Newfoundland Power	2.3	14.1	2.7
Nova Scotia Power	2.5	13.8	3.4
Toronto Hydro	2.3	17.7	3.5
Veridian	3.4	29.5	4.2
Gas Distributors			
Enbridge Gas Distribution	2.1	11.5	2.6
Gaz Metropolitain	2.5	20.9	5.0
Pacific Northern Gas	2.4	12.5	2.5
Terasen Gas	2.0	9.1	2.4
Terasen Gas (Vancouver Is.)	2.8	10.3	3.1
Union Gas	2.1	12.4	2.8
Pipelines			
Enbridge Pipelines	3.3	16.9	3.5
Nova Gas Transmission Ltd.	2.4	19.0	3.2
Trans Quebec & Maritimes	2.4	10.4	2.7
TransCanada PipeLines Ltd.	2.5	14.3	2.8
Westcoast Energy Inc.	2.2	17.0	3.2
Medians			
Electric T&D	**2.8**	**17.7**	**3.9**
Electric Integrated	**2.5**	**13.8**	**3.4**
All Electric	**2.6**	**16.0**	**3.5**
Gas Distributors	**2.3**	**12.0**	**2.7**
Pipelines	**2.4**	**16.9**	**3.2**
All Companies	**2.5**	**14.5**	**3.2**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

Source: Annual Reports to Shareholders and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES RATED A- or HIGHER

	S&P									
				Average 2005-2007 [1/]					Common	Average
Name	Debt Rating	Business Profile	Financial Profile	Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	Moody's Debt Rating	Equity Ratio (2008) [2/]	ROE 2006-2008
Alabama Power Co.	A	Excellent	Intermediate	52.7	4.2	21.8	5.3	A2	42.5	13.4
Central Hudson Gas & Electric Corp.	A	Excellent	Intermediate	61.4	4.5	16.1	4.5	A2	43.7	9.3
Florida Power & Light Co.	A	Excellent	Intermediate	43.3	5.0	30.3	6.3	A1	56.0	10.9
FPL Group Inc.	A	Excellent	Intermediate	51.4	2.9	25.8	5.3	A2	40.6	13.7
Georgia Power Co.	A	Excellent	Intermediate	49.7	4.8	23.3	5.5	A2	46.5	13.7
Gulf Power Co.	A	Excellent	Intermediate	53.2	3.8	20.1	4.6	A2	42.9	12.4
Mississippi Power Co.	A	Excellent	Intermediate	47.0	6.9	44.7	11.3	A1	57.5	14.0
San Diego Gas & Electric Co.	A	Excellent	Intermediate	51.5	3.4	30.5	4.6	A2	53.3	14.0
Southern Co.	A	Excellent	Intermediate	56.4	3.6	21.3	5.1	A3	40.5	14.1
Consolidated Edison Co. of New York Inc.	A-	Excellent	Intermediate	54.1	3.0	15.5	3.6	A1	48.8	10.1
Consolidated Edison Inc.	A-	Excellent	Intermediate	57.1	2.9	14.7	3.6	A2	48.5	11.1
Dominion Resources	A-	Excellent	Aggressive	60.3	2.5	13.0	3.1	Baa2	36.3	18.3
Duke Energy Carolinas LLC	A-	Excellent	Intermediate	47.9	4.1	31.3	9.9	A3	na	na
Duke Energy Corp.	A-	Excellent	Intermediate	44.3	3.6	22.4	4.5	Baa2	59.2	7.1
Duke Energy Indiana Inc. 3/	A-	Excellent	Intermediate	55.0	3.1	17.4	4.4	Baa1	46.7	9.1
Duke Energy Kentucky	A-	Excellent	Intermediate	69.0	1.3	8.2	2.7	Baa1	na	na
Duke Energy Ohio Inc.	A-	Excellent	Intermediate	32.1	3.9	24.0	5.4	Baa1	na	na
MidAmerican Energy Co.	A-	Excellent	Aggressive	53.0	4.2	23.3	5.3	A2	43.4	14.6
Northern States Power (Wisconsin)	A-	Excellent	Intermediate	44.9	3.4	24.0	4.9	A3	51.3	9.3
PacifiCorp	A-	Excellent	Aggressive	55.6	2.8	16.8	3.8	Baa1	51.1	7.1
PPL Electric Utilities Corp.	A-	Excellent	Intermediate	52.3	3.4	20.4	4.1	Baa1	38.3	12.5
SCANA Corp.	A-	Excellent	Aggressive	57.5	2.4	19.6	4.3	Baa1	39.3	11.2
South Carolina Electric & Gas Co.	A-	Excellent	Aggressive	49.1	2.6	27.3	5.3	A3	44.9	9.5
Southern Indiana Gas & Electric	A-	Excellent	Intermediate	46.1	3.7	23.5	4.8	Baa1	na	na
Virginia Electric Power 3/	A-	Excellent	Aggressive	52.5	3.2	20.0	4.4	Baa1	47.1	6.5
Wisconsin Electric Power Co.	A-	Excellent	Intermediate	46.4	3.7	28.3	5.3	A1	46.7	11.1
Wisconsin Power & Light Co.	A-	Excellent	Intermediate	50.8	3.8	20.2	4.8	A2	53.7	10.0
Wisconsin Public Service Corp.	A-	Excellent	Aggressive	55.5	3.1	18.7	4.1	A1	54.2	10.1
NSTAR	A+	Excellent	Intermediate	62.4	3.5	23.2	5.3	A2	36.8	13.5
Madison Gas & Electric Co.	AA-	Excellent	Intermediate	50.8	4.6	20.5	5.4	Aa3	53.6	11.1
Mean	**A-**	**Excellent**	**Intermediate**	**52.1**	**3.6**	**22.2**	**5.1**	**A3**	**47.1**	**11.4**
Median	**A-**	**Excellent**	**Intermediate**	**52.4**	**3.6**	**21.6**	**4.8**	**A2/A3**	**46.7**	**11.1**

[1/] S&P Credit Stats

[2/] Equity ratio based on total capital.

[3/] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: Standard and Poor's Research Insight; S&P, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest,* March 31, 2009; S&P, *Credit Stats,* September 2008 and www.moodys.com

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. NATURAL GAS UTILITIES RATED A- OR HIGHER

	S&P									
				Average 2005-2007[1/]						
Name	**Debt Rating**	**Business Profile**	**Financial Profile**	**Debt Ratio**	**EBIT Coverage**	**FFO/Debt**	**FFO Coverage**	**Moody's Debt Rating**	**Common Equity Ratio (2008)[2/]**	**Average ROE 2006-2008**
AGL Resources Inc.	A-	Excellent	Intermediate	58.2	3.7	19.6	4.4	A3	39.4	13.2
Indiana Gas Co. Inc.	A-	Excellent	Intermediate	48.0	2.8	16.4	3.6	Baa1	na	na
Laclede Gas Co.	A	Excellent	Intermediate	60.0	2.3	13.8	3.1	Baa1	34.0	9.7
Laclede Group	A	Excellent	Intermediate	57.9	3.0	17.7	3.6	na	44.5	13.9
New Jersey Natural Gas	A	Excellent	Intermediate	42.8	5.4	24.2	5.5	A1	51.2	13.9
Nicor Inc.	AA	Excellent	Intermediate	45.3	3.9	28.3	6.0	A3	44.0	14.2
Nicor Gas	AA	Excellent	Intermediate	47.1	2.7	19.7	4.7	na	na	na
North Shore Gas	A-	Excellent	Intermediate	45.6	4.5	20.6	4.9	A2	54.8	7.1
Northwest Natural Gas Co.	AA-	Excellent	Intermediate	53.4	3.6	21.2	4.4	A3	45.3	11.5
Piedmont Natural Gas Co. Inc.	A	Excellent	Intermediate	50.5	3.9	24.9	4.9	A3	41.9	11.8
Public Service (North Carolina) 4/	A-	Excellent	Aggressive	42.1	2.9	14.3	3.3	A3	58.3	5.3
Southern California Gas Co.	A	Excellent	Intermediate	56.2	4.6	30.6	6.4	A2	50.9	16.0
Vectren Corp.	A-	Excellent	Intermediate	58.4	2.8	17.1	4.0	na	42.2	10.4
Vectren Utility Holdings Inc.	A-	Excellent	Intermediate	53.7	2.9	19.0	4.1	Baa1	48.2	9.4
Washington Gas Light Co.	AA-	Excellent	Intermediate	50.8	4.6	24.1	5.5	A2	49.9	10.9
WGL Holdings Inc.	AA-	Excellent	Intermediate	52.8	4.6	22.2	5.3	na	51.7	10.8
Mean	**A**	**Excellent**	**Intermediate**	**51.4**	**3.6**	**20.9**	**4.6**	**A3**	**46.9**	**11.3**
Median	**A**	**Excellent**	**Intermediate**	**51.8**	**3.7**	**20.2**	**4.5**	**A3**	**46.7**	**11.2**

[1/] S&P Credit Stats

[2/] Equity ratio based on total capital.

[3/] ROE and equity ratio for New Jersey Resources Corp.

[4/] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: Standard &Poor's Research Insight; S&P: *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, March 10, 2009* and S&P, *Credit Stats* , September 2008 and www.moodys.com

HISTORIC EQUITY MARKET RISK PREMIUMS

(ARITHMETIC AVERAGES)

Canada (1947-2008)

Stock Return	Bond Total Return	Risk Premium
11.6	7.0	4.6

Stock Return	Bond Income Return	Risk Premium
11.6	7.2	4.4

United States (1947-2008)

Stock Return	Bond Total Return	Risk Premium
12.2	6.6	5.6

Stock Return	Bond Income Return	Risk Premium
12.2	6.0	6.2

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008* ; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006 ; www.standardandpoors.com, *TSX Review*
www.federalreserve.gov

HISTORIC EQUITY MARKET
RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2008)

Stock Return	Bond Total Return	Risk Premium
11.3	6.6	4.7

Stock Return	Bond Income Return	Risk Premium
11.3	6.3	5.0

United States
(1926-2008)

Stock Return	Bond Total Return	Risk Premium
11.7	6.1	5.6

Stock Return	Bond Income Return	Risk Premium
11.7	5.2	6.5

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008* ; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006 ; www.standardandpoors.com, *TSX Review*
www.federalreserve.gov

10-YEAR ROLLING AVERAGE CANADIAN MARKET RETURNS

	Canadian Stock Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1947-1956	18.94%	1.40%	17.53%	3.21%	15.72%
1948-1957	16.84%	1.68%	15.17%	3.37%	13.47%
1949-1958	18.76%	1.35%	17.41%	3.50%	15.26%
1950-1959	16.95%	0.42%	16.54%	3.72%	13.23%
1951-1960	12.29%	1.14%	11.15%	3.96%	8.32%
1952-1961	13.16%	2.43%	10.73%	4.15%	9.01%
1953-1962	12.49%	2.54%	9.96%	4.31%	8.18%
1954-1963	13.84%	2.60%	11.24%	4.46%	9.38%
1955-1964	12.48%	2.30%	10.18%	4.67%	7.81%
1956-1965	10.36%	2.43%	7.94%	4.88%	5.48%
1957-1966	8.33%	2.94%	5.39%	5.10%	3.24%
1958-1967	12.20%	2.14%	10.07%	5.29%	6.91%
1959-1968	11.32%	2.62%	8.70%	5.57%	5.76%
1960-1969	10.78%	2.87%	7.92%	5.83%	4.95%
1961-1970	10.25%	4.35%	5.89%	6.12%	4.13%
1962-1971	7.77%	4.53%	3.24%	6.32%	1.45%
1963-1972	11.22%	4.34%	6.88%	6.55%	4.67%
1964-1973	9.69%	4.08%	5.60%	6.81%	2.88%
1965-1974	4.55%	3.22%	1.33%	7.20%	-2.65%
1966-1975	5.73%	3.40%	2.33%	7.61%	-1.88%
1967-1976	7.54%	5.15%	2.39%	7.99%	-0.45%
1968-1977	6.80%	5.97%	0.84%	8.28%	-1.48%
1969-1978	7.53%	6.18%	1.35%	8.55%	-1.03%
1970-1979	12.09%	6.11%	5.97%	8.84%	3.25%
1971-1980	15.46%	4.12%	11.33%	9.34%	6.12%
1972-1981	13.63%	2.67%	10.97%	10.26%	3.37%
1973-1982	11.45%	6.85%	4.59%	11.03%	0.42%
1974-1983	14.97%	7.64%	7.33%	11.49%	3.48%
1975-1984	17.32%	9.32%	8.00%	11.92%	5.40%
1976-1985	17.98%	11.56%	6.42%	12.14%	5.84%
1977-1986	17.77%	11.42%	6.36%	12.18%	5.60%
1978-1987	17.29%	10.86%	6.43%	12.31%	4.98%
1979-1988	15.43%	11.78%	3.65%	12.41%	3.01%
1980-1989	13.09%	13.67%	-0.58%	12.38%	0.71%
1981-1990	8.59%	13.80%	-5.20%	12.20%	-3.61%
1982-1991	10.82%	16.54%	-5.72%	11.59%	-0.77%
1983-1992	10.12%	13.55%	-3.43%	10.98%	-0.85%
1984-1993	9.83%	14.88%	-5.05%	10.55%	-0.72%
1985-1994	10.05%	12.33%	-2.27%	10.09%	-0.04%
1986-1995	9.00%	12.43%	-3.43%	9.79%	-0.79%
1987-1996	10.94%	12.10%	-1.17%	9.57%	1.36%
1988-1997	11.85%	13.80%	-1.96%	9.19%	2.65%
1989-1998	10.58%	14.17%	-3.59%	8.68%	1.90%
1990-1999	11.61%	11.83%	-0.21%	8.23%	3.38%
1991-2000	13.83%	12.86%	0.98%	7.69%	6.14%
1992-2001	11.38%	10.81%	0.57%	7.27%	4.11%
1993-2002	10.28%	10.51%	-0.23%	6.93%	3.34%
1994-2003	9.69%	9.03%	0.67%	6.65%	3.04%
1995-2004	11.16%	10.92%	0.24%	6.26%	4.90%
1996-2005	12.12%	9.79%	2.32%	5.86%	6.25%
1997-2006	11.01%	8.69%	2.32%	5.50%	5.51%
1998-2007	10.47%	7.27%	3.20%	5.24%	5.23%
1999-2008	7.33%	7.22%	0.12%	5.09%	2.24%

Source: Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008*;
Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2006*, *TSX Review*

10-YEAR ROLLING AVERAGE U.S. MARKET RETURNS

	US Stock Returns	US Bond Total Returns	US Risk Premium Bond Total Returns	US Bond Income Returns	US Risk Premium Bond Income Returns
1947-1956	19.38%	0.85%	18.54%	2.53%	16.85%
1948-1957	17.74%	1.86%	15.88%	2.66%	15.07%
1949-1958	21.52%	0.91%	20.62%	2.75%	18.77%
1950-1959	20.84%	0.04%	20.80%	2.93%	17.91%
1951-1960	17.71%	1.41%	16.31%	3.14%	14.58%
1952-1961	18.00%	1.90%	16.10%	3.28%	14.72%
1953-1962	15.29%	2.47%	12.82%	3.42%	11.87%
1954-1963	17.67%	2.23%	15.44%	3.52%	14.15%
1955-1964	14.06%	1.86%	12.20%	3.66%	10.40%
1956-1965	12.15%	2.06%	10.09%	3.80%	8.34%
1957-1966	10.48%	2.98%	7.50%	3.95%	6.53%
1958-1967	13.96%	1.32%	12.64%	4.07%	9.89%
1959-1968	10.73%	1.90%	8.83%	4.29%	6.44%
1960-1969	8.68%	1.62%	7.06%	4.49%	4.20%
1961-1970	9.04%	1.45%	7.58%	4.73%	4.30%
1962-1971	7.78%	2.68%	5.10%	4.98%	2.80%
1963-1972	10.55%	2.56%	7.99%	5.17%	5.38%
1964-1973	6.80%	2.33%	4.48%	5.43%	1.37%
1965-1974	2.51%	2.41%	0.10%	5.74%	-3.23%
1966-1975	4.98%	3.26%	1.72%	6.12%	-1.14%
1967-1976	8.37%	4.57%	3.80%	6.46%	1.91%
1968-1977	5.26%	5.42%	-0.16%	6.72%	-1.46%
1969-1978	4.81%	5.33%	-0.52%	6.96%	-2.15%
1970-1979	7.50%	5.71%	1.79%	7.25%	0.25%
1971-1980	10.34%	4.11%	6.24%	7.57%	2.77%
1972-1981	8.42%	2.97%	5.45%	8.10%	0.33%
1973-1982	8.67%	6.44%	2.23%	8.86%	-0.19%
1974-1983	12.38%	6.61%	5.77%	9.25%	3.14%
1975-1984	15.66%	7.73%	7.93%	9.69%	5.96%
1976-1985	15.15%	9.90%	5.25%	10.02%	5.13%
1977-1986	14.61%	10.68%	3.93%	10.13%	4.49%
1978-1987	15.86%	10.48%	5.38%	10.21%	5.65%
1979-1988	16.88%	11.56%	5.32%	10.31%	6.57%
1980-1989	18.19%	13.50%	4.69%	10.31%	7.88%
1981-1990	14.63%	14.51%	0.12%	10.13%	4.50%
1982-1991	18.17%	16.25%	1.92%	9.80%	8.38%
1983-1992	16.80%	13.02%	3.78%	9.17%	7.63%
1984-1993	15.55%	14.78%	0.76%	8.85%	6.70%
1985-1994	15.05%	12.46%	2.59%	8.34%	6.71%
1986-1995	15.58%	12.53%	3.05%	7.97%	7.61%
1987-1996	16.04%	9.98%	6.06%	7.69%	8.35%
1988-1997	18.85%	11.84%	7.01%	7.56%	11.29%
1989-1998	20.03%	12.18%	7.85%	7.25%	12.78%
1990-1999	18.98%	9.47%	9.51%	6.93%	12.06%
1991-2000	18.39%	11.00%	7.39%	6.76%	11.63%
1992-2001	14.15%	9.44%	4.71%	6.49%	7.66%
1993-2002	11.17%	10.42%	0.75%	6.32%	4.85%
1994-2003	13.04%	8.74%	4.30%	6.08%	6.96%
1995-2004	14.00%	10.37%	3.63%	5.93%	8.07%
1996-2005	10.74%	7.98%	2.76%	5.64%	5.11%
1997-2006	10.02%	8.19%	1.82%	5.49%	4.53%
1998-2007	7.23%	7.60%	-0.37%	5.31%	1.92%
1999-2008	0.67%	8.88%	-8.21%	5.17%	-4.50%

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ,
www.federalreserve.gov, www.standardandpoors.com

**FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS
FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
FOR FIVE YEAR PERIODS ENDING:**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**2.86**	**4.35**	**4.52**
10 Sector Indices													
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.51
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.94
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	6.63
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	4.78
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	7.65
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.58
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	13.08
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	6.55
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	6.17
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.02
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.29**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.74**

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:													
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.74**	**0.71**	**0.64**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.71**

Source: *TSX Review*

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49

Source: *TSX Review*

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS

	Compound Returns						Betas					
	56-03	**56-97**	**64-73**	**74-83**	**84-93**	**94-03**	**56-03**	**56-97**	**64-73**	**74-83**	**84-93**	**94-03**
Metals/Minerals	0.08	0.08	0.07	0.11	0.07	0.07	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	0.10	0.10	0.16	0.16	0.11	-0.03	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	0.10	0.08	0.15	0.12	0.05	0.15	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	0.07	0.07	0.05	0.12	0.10	0.03	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	0.11	0.12	0.10	0.14	0.11	0.10	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	0.07	0.10	0.08	0.11	0.06	0.01	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [1/]	0.05	0.05	0.01	0.17	-0.02	0.01	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	0.10	0.11	0.13	0.18	0.03	0.09	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	0.12	0.12	0.05	0.14	0.14	0.13	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	0.11	0.11	0.03	0.18	0.11	0.16	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	0.13	0.15	0.19	0.15	0.13	0.07	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	0.10	0.11	0.11	0.12	0.09	0.07	0.78	0.86	0.93	0.84	0.83	0.46
Finance	0.12	0.13	0.12	0.12	0.12	0.18	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	0.11	0.11	0.13	0.15	0.09	0.14	0.94	1.03	1.26	0.97	1.20	0.68
Intercept							**0.18**	**0.18**	**0.12**	**0.15**	**0.14**	**0.12**
Adjusted R Square							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Data only available starting July 1961

Source: *TSX Review*

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS

	Compound Returns [1/]			Betas		
	88-08	**88-97**	**99-08**	**88-08**	**88-97**	**99-08**
Consumer Discretionary	0.058	0.102	0.009	0.761	0.904	0.676
Consumer Staples	0.116	0.127	0.092	0.351	0.727	0.105
Energy	0.099	0.084	0.165	0.774	0.765	0.767
Financials	0.119	0.183	0.067	0.761	1.039	0.471
Health Care	0.016	0.155	-0.104	0.806	0.807	0.698
Industrials	0.050	0.083	0.033	0.947	1.131	0.863
Information Technology	0.050	0.218	-0.097	1.746	1.213	2.189
Materials	0.057	0.034	0.102	0.970	1.257	0.814
Telecommunication Services	0.124	0.154	0.084	0.720	0.578	0.698
Utilities	0.098	0.115	0.088	0.300	0.624	0.065
Intercept				**0.12**	**0.14**	**0.11**
Adjusted R Square				**26%**	**1%**	**32%**
Beta				**-0.047**	**-0.017**	**-0.084**

[1/] Data only available starting December 1987

Source: *TSX Review*

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 [3]
Canadian Utilities	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.41
Emera	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.38
Enbridge	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.56
Fortis	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.49
PNG	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54	0.35	0.26	0.21
Terasen Inc [1]	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na	na	na	na
TransCanada Pipelines	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.47
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**	**0.48**	**0.25**	**0.42**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**	**0.53**	**0.24**	**0.44**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.56

Adjusted Betas [2]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 [3]
Canadian Utilities	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.61
Emera	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.59
Enbridge	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.70
Fortis	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.66
PNG	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69	0.56	0.50	0.47
Terasen Inc	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na	na	na	na
TransCanada Pipelines	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.65
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**	**0.65**	**0.50**	**0.61**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**	**0.68**	**0.49**	**0.63**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.71

[1] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.

[2] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

[3] Three-year beta calculated through March 2009.

Source: Standard and Poor's Research Insight and *TSX Review*.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK US ELECTRIC AND GAS UTILITIES (Annual Averages of Monthly Data)

	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Risk Premium
1991	7.0	4.6	11.6	8.1	3.6
1992	6.4	4.4	10.8	7.7	3.1
1993	5.6	4.6	10.1	6.6	3.6
1994	6.3	4.1	10.4	7.4	3.0
1995	6.1	3.9	9.9	6.8	3.1
1996	5.7	4.0	9.7	6.7	3.0
1997	5.5	4.2	9.8	6.6	3.2
1998	4.7	4.6	9.4	5.5	3.8
1999	5.1	5.0	10.2	5.9	4.3
2000	5.2	5.7	11.0	5.9	5.1
2001	4.8	6.6	11.4	5.5	6.0
2002	4.8	6.4	11.2	5.4	5.8
2003	4.9	5.2	10.1	5.0	5.1
2004	4.5	4.6	9.1	5.1	4.0
2005	4.1	4.7	8.8	4.5	4.3
2006	4.2	5.3	9.6	4.9	4.7
2007	4.1	5.3	9.4	4.8	4.6
2008	4.5	5.7	10.2	4.2	6.0
2009 (Through March)	5.3	5.7	11.0	3.6	7.4
Means for Long Treasury Yields:					
Under 5.0	**4.4**	**5.3**	**9.7**	**4.6**	**5.1**
5.0-5.99	**4.8**	**5.5**	**10.3**	**5.5**	**4.8**
6.0-6.99	**5.6**	**4.4**	**10.0**	**6.5**	**3.5**
7.0 and above	**6.5**	**4.3**	**10.8**	**7.7**	**3.1**
Means:					
1991 - 2009Q1	**5.2**	**5.0**	**10.2**	**5.9**	**4.3**
1993 - 2009Q1	**5.0**	**5.0**	**10.0**	**5.6**	**4.4**
1998 - 2009Q1	**4.7**	**5.4**	**10.1**	**5.1**	**4.9**

[1/] Dividend Yield is adjusted for I/B/E/S/ growth
Source: Standard & Poor's Research Insight, I/B/E/S and www.federalreserve.gov

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR
BENCHMARK US ELECTRIC AND GAS UTILITIES
Regression Analysis Results**

Equation 1:

Equity Risk Premium = 8.40 - 0.70 (30-Year Treasury Yield)

t-statistics:
Long-term Bond Yield = -15.81
R^2 = 53%

Equity Risk Premium at Long-Term Bond Yield of 4.25% = 5.42

Equation 2:

Equity Risk Premium = 4.97 - 0.42 (30-Year Treasury Yield) + 1.23 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
Long-term Bond Yield = -13.55
Utility/government bond yield spread = 19.21

R^2 = 83%

Equity Risk Premium at Long-term Bond Yield of 4.25% and Spread of 2.25-2.50 = 6.1

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1956-2008)

Utilities Index Return	Bond Total Return	Risk Premium
12.0	7.9	4.1

Utilities Index Return	Bond Income Return	Risk Premium
12.0	7.8	4.2

United States
(1947-2008)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
10.8	6.6	4.2

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
10.8	6.0	4.8

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
12.1	6.6	5.5

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
12.1	6.0	6.1

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2008.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2008 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2008 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008* ; Canadian Institute of Actuaries
Report on Canadian Economic Statistics 1924-2006 ; www.standardandpoors.com, *TSX Review*
Mergent Corporate News Reports, www.federal reserve.com

10-YEAR ROLLING AVERAGE RETURNS FOR CANADIAN UTILITIES AND GOVERNMENT BONDS

	S&P/TSX Utilities Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1956-1965	14.3%	2.4%	11.9%	4.9%	9.4%
1957-1966	10.1%	2.9%	7.1%	5.1%	5.0%
1958-1967	11.3%	2.1%	9.2%	5.3%	6.0%
1959-1968	10.8%	2.6%	8.2%	5.6%	5.2%
1960-1969	7.9%	2.9%	5.0%	5.8%	2.1%
1961-1970	7.2%	4.4%	2.8%	6.1%	1.0%
1962-1971	6.9%	4.5%	2.4%	6.3%	0.6%
1963-1972	9.2%	4.3%	4.9%	6.5%	2.7%
1964-1973	6.9%	4.1%	2.8%	6.8%	0.1%
1965-1974	6.1%	3.2%	2.8%	7.2%	-1.1%
1966-1975	4.7%	3.4%	1.3%	7.6%	-2.9%
1967-1976	9.3%	5.1%	4.1%	8.0%	1.3%
1968-1977	9.6%	6.0%	3.6%	8.3%	1.3%
1969-1978	9.2%	6.2%	3.1%	8.6%	0.7%
1970-1979	13.6%	6.1%	7.5%	8.8%	4.8%
1971-1980	13.8%	4.1%	9.7%	9.3%	4.5%
1972-1981	12.2%	2.7%	9.5%	10.3%	1.9%
1973-1982	15.4%	6.9%	8.5%	11.0%	4.3%
1974-1983	17.2%	7.6%	9.6%	11.5%	5.7%
1975-1984	19.5%	9.3%	10.2%	11.9%	7.6%
1976-1985	19.7%	11.6%	8.1%	12.1%	7.5%
1977-1986	17.3%	11.4%	5.9%	12.2%	5.2%
1978-1987	15.9%	10.9%	5.1%	12.3%	3.6%
1979-1988	15.4%	11.8%	3.7%	12.4%	3.0%
1980-1989	12.8%	13.7%	-0.9%	12.4%	0.4%
1981-1990	11.1%	13.8%	-2.7%	12.2%	-1.1%
1982-1991	12.1%	16.5%	-4.5%	11.6%	0.5%
1983-1992	8.9%	13.6%	-4.7%	11.0%	-2.1%
1984-1993	10.4%	14.9%	-4.5%	10.5%	-0.1%
1985-1994	9.2%	12.3%	-3.1%	10.1%	-0.9%
1986-1995	7.2%	12.4%	-5.2%	9.8%	-2.6%
1987-1996	8.8%	12.1%	-3.3%	9.6%	-0.7%
1988-1997	12.0%	13.8%	-1.8%	9.2%	2.8%
1989-1998	11.2%	14.2%	-2.9%	8.7%	2.5%
1990-1999	8.2%	11.8%	-3.6%	8.2%	0.0%
1991-2000	12.8%	12.9%	-0.1%	7.7%	5.1%
1992-2001	13.7%	10.8%	2.9%	7.3%	6.4%
1993-2002	13.7%	10.5%	3.1%	6.9%	6.7%
1994-2003	14.0%	9.0%	5.0%	6.7%	7.3%
1995-2004	14.2%	10.9%	3.3%	6.3%	8.0%
1996-2005	17.7%	9.8%	7.9%	5.9%	11.9%
1997-2006	16.0%	8.7%	7.3%	5.5%	10.5%
1998-2007	13.5%	7.3%	6.2%	5.2%	8.3%
1999-2008	11.1%	7.2%	3.9%	5.1%	6.0%

Source:
Ibbotson Associates, *Canadian Risk Premia Over Time Report 2008*; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2006*; *TSX Review*

10-YEAR ROLLING AVERAGE RETURNS FOR

U.S. UTILITIES AND GOVERNMENT BONDS

	S&P/Moody's Gas Distributors Returns	S&P/Moody's Electric Returns	US Bond Total Returns	US Gas Risk Premium Bond Total Returns	US Electric Risk Premium Bond Total Returns	US Bond Income Returns	US Gas Risk Premium Bond Income Returns	US Electric Risk Premium Bond Income Returns
1947-1956	12.4%	10.4%	0.8%	11.5%	9.5%	2.5%	9.8%	7.8%
1948-1957	12.6%	12.6%	1.9%	10.8%	10.8%	2.7%	10.0%	10.0%
1949-1958	15.7%	16.3%	0.9%	14.8%	15.4%	2.7%	12.9%	13.6%
1950-1959	12.6%	14.3%	0.0%	12.6%	14.3%	2.9%	9.7%	11.4%
1951-1960	14.6%	16.0%	1.4%	13.2%	14.6%	3.1%	11.5%	12.9%
1952-1961	15.9%	17.2%	1.9%	14.0%	15.3%	3.3%	12.6%	13.9%
1953-1962	14.3%	15.4%	2.5%	11.9%	12.9%	3.4%	10.9%	11.9%
1954-1963	15.0%	15.5%	2.2%	12.8%	13.2%	3.5%	11.5%	12.0%
1955-1964	13.5%	14.7%	1.9%	11.6%	12.8%	3.7%	9.8%	11.0%
1956-1965	12.4%	13.7%	2.1%	10.4%	11.7%	3.8%	8.6%	9.9%
1957-1966	9.9%	13.0%	3.0%	6.9%	10.0%	4.0%	6.0%	9.1%
1958-1967	10.8%	11.7%	1.3%	9.5%	10.4%	4.1%	6.7%	7.6%
1959-1968	8.6%	8.7%	1.9%	6.7%	6.8%	4.3%	4.3%	4.5%
1960-1969	6.9%	6.9%	1.6%	5.2%	5.3%	4.5%	2.4%	2.4%
1961-1970	7.9%	6.0%	1.5%	6.4%	4.6%	4.7%	3.2%	1.3%
1962-1971	4.7%	3.3%	2.7%	2.1%	0.7%	5.0%	-0.3%	-1.6%
1963-1972	6.5%	3.6%	2.6%	4.0%	1.0%	5.2%	1.4%	-1.6%
1964-1973	3.8%	0.7%	2.3%	1.4%	-1.6%	5.4%	-1.7%	-4.7%
1965-1974	2.7%	-3.4%	2.4%	0.3%	-5.8%	5.7%	-3.0%	-9.1%
1966-1975	5.1%	1.4%	3.3%	1.9%	-1.9%	6.1%	-1.0%	-4.8%
1967-1976	11.4%	4.1%	4.6%	6.8%	-0.4%	6.5%	4.9%	-2.3%
1968-1977	11.4%	5.3%	5.4%	6.0%	-0.1%	6.7%	4.7%	-1.4%
1969-1978	9.4%	4.1%	5.3%	4.1%	-1.2%	7.0%	2.4%	-2.9%
1970-1979	14.6%	5.5%	5.7%	8.9%	-0.2%	7.2%	7.4%	-1.8%
1971-1980	14.7%	4.9%	4.1%	10.6%	0.8%	7.6%	7.1%	-2.7%
1972-1981	13.6%	6.7%	3.0%	10.6%	3.8%	8.1%	5.5%	-1.4%
1973-1982	12.0%	9.9%	6.4%	5.6%	3.4%	8.9%	3.2%	1.0%
1974-1983	17.1%	13.1%	6.6%	10.5%	6.5%	9.2%	7.9%	3.8%
1975-1984	18.7%	18.1%	7.7%	11.0%	10.4%	9.7%	9.0%	8.4%
1976-1985	18.2%	15.6%	9.9%	8.3%	5.7%	10.0%	8.2%	5.6%
1977-1986	15.9%	16.0%	10.7%	5.3%	5.4%	10.1%	5.8%	5.9%
1978-1987	14.0%	14.4%	10.5%	3.6%	3.9%	10.2%	3.8%	4.2%
1979-1988	16.4%	16.5%	11.6%	4.8%	4.9%	10.3%	6.1%	6.2%
1980-1989	17.1%	19.8%	13.5%	3.6%	6.3%	10.3%	6.8%	9.4%
1981-1990	13.9%	19.3%	14.5%	-0.6%	4.8%	10.1%	3.8%	9.2%
1982-1991	17.0%	20.3%	16.3%	0.7%	4.0%	9.8%	7.2%	10.5%
1983-1992	19.0%	17.3%	13.0%	5.9%	4.3%	9.2%	9.8%	8.2%
1984-1993	17.2%	17.3%	14.8%	2.5%	2.5%	8.9%	8.4%	8.4%
1985-1994	14.2%	13.5%	12.5%	1.8%	1.0%	8.3%	5.9%	5.1%
1986-1995	15.3%	14.0%	12.5%	2.8%	1.5%	8.0%	7.3%	6.1%
1987-1996	13.9%	11.2%	10.0%	3.9%	1.2%	7.7%	6.2%	3.5%
1988-1997	16.8%	14.6%	11.8%	5.0%	2.8%	7.6%	9.3%	7.0%
1989-1998	14.5%	15.2%	12.2%	2.3%	3.0%	7.2%	7.2%	8.0%
1990-1999	10.0%	10.2%	9.5%	0.5%	0.7%	6.9%	3.1%	3.2%
1991-2000	12.7%	15.8%	11.0%	1.7%	4.8%	6.8%	5.9%	9.1%
1992-2001	11.0%	12.3%	9.4%	1.6%	2.9%	6.5%	4.6%	5.8%
1993-2002	9.8%	10.6%	10.4%	-0.6%	0.2%	6.3%	3.5%	4.3%
1994-2003	10.1%	11.2%	8.7%	1.3%	2.5%	6.1%	4.0%	5.1%
1995-2004	12.8%	14.1%	10.4%	2.4%	3.7%	5.9%	6.8%	8.2%
1996-2005	9.6%	11.9%	8.0%	1.6%	3.9%	5.6%	3.9%	6.2%
1997-2006	10.7%	13.7%	8.2%	2.5%	5.5%	5.5%	5.2%	8.2%
1998-2007	8.8%	12.4%	7.6%	1.2%	4.8%	5.3%	3.5%	7.1%
1999-2008	9.6%	7.4%	8.9%	0.8%	-1.4%	5.2%	4.5%	2.3%

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2009 Yearbook* ;
www.standardandpoors.com, Mergent Corporate News Reports,
www.federal reserve.com

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF U.S. ELECTRIC AND GAS UTILITIES

	Value Line							S & P		Moody's	Average
	Safety	Forecast Common Equity Ratio 2012-2014	Forecast Return On Average Common Equity 2012-2014	Dividend Payout Forecast 2012-2014	Beta	Research Insight Beta 1/	Common Equity Ratio 2008	Business Risk Profile	Debt Rating	Debt Rating	Market/ Book Ratio 2008
AGL Resources	2	55.0%	15.2%	58.8%	0.75	0.312	39.4%	Excellent	A-	Baa1	1.36
Consolidated Edison	1	53.5%	9.0%	64.2%	0.65	0.339	48.5%	Excellent	A-	A2	1.08
Dominion Resources	2	47.5%	15.0%	55.0%	0.65	0.565	36.3%	Excellent	A-	Baa2	1.89
Duke Energy	2	53.5%	8.4%	73.3%	NMF	0.395	59.2%	Excellent	A-	Baa2	0.87
FPL	1	45.0%	14.6%	38.3%	0.75	0.683	40.6%	Excellent	A	A2	1.70
New Jersey Resources	1	67.0%	11.4%	49.1%	0.65	0.200	51.2%	Excellent	A	A1	2.12
Northwest Nat. Gas	1	53.0%	11.6%	58.0%	0.60	0.395	45.3%	Excellent	AA-	A3	1.79
NSTAR	1	51.5%	15.0%	60.0%	0.65	0.351	36.8%	Excellent	A+	A2	1.95
Piedmont Natural Gas	2	53.0%	14.0%	58.1%	0.65	0.328	41.9%	Excellent	A	A3	2.14
Scana	2	42.0%	10.9%	60.0%	0.65	0.630	39.3%	Excellent	A-	Baa1	1.24
Southern Co.	1	44.0%	13.8%	66.7%	0.55	0.465	40.5%	Excellent	A	A3	1.88
Vectren	2	52.0%	10.5%	64.3%	0.75	0.358	42.2%	Excellent	A-	Baa1	1.37
WGL Holdings Inc.	1	64.5%	10.6%	58.2%	0.65	0.323	51.7%	Excellent	AA-	A2	1.53
Mean	**1**	**52.4%**	**12.3%**	**58.8%**	**0.66**	**0.41**	**44.1%**	**Excellent**	**A**	**A3**	**1.61**
Median	**1**	**53.0%**	**11.6%**	**58.8%**	**0.65**	**0.36**	**41.9%**	**Excellent**	**A**	**A3**	**1.70**

1/ Calculated using monthly data against the S&P 500 (60 months ending March 2009).

Source: Standard and Poor's Research Insight, *Value Line* (February and March 2009), www.moodys.com,
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (March 31, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (March 10, 2009).

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF U.S. ELECTRIC AND GAS UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average Monthly High/Low Prices Jan 2009-Mar 2009	Expected Dividend Yield [1/]	Average I/B/E/S Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	29.30	6.1	4.3	10.4
Consolidated Edison	2.36	38.41	6.3	2.5	8.8
Dominion Resources	1.75	32.69	5.8	7.8	13.5
Duke Energy	0.92	14.35	6.7	4.5	11.1
FPL	1.89	48.70	4.3	9.6	13.9
New Jersey Resources	1.24	36.57	3.6	7.0	10.6
Northwest Nat. Gas	1.58	42.36	3.9	4.8	8.7
NSTAR	1.50	32.61	4.9	6.0	10.9
Piedmont Natural Gas	1.08	25.89	4.5	7.1	11.6
Scana	1.88	32.05	6.1	4.6	10.7
Southern Co.	1.68	32.11	5.5	5.4	10.9
Vectren	1.34	22.87	6.3	7.2	13.5
WGL Holdings Inc.	1.42	32.05	4.6	4.0	8.6
Mean	**1.57**	**32.30**	**5.3**	**5.7**	**11.0**
Median	**1.58**	**32.11**	**5.5**	**5.4**	**10.9**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))

[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, www.yahoo.com and I/B/E/S (March 2009)

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF
U.S. ELECTRIC AND GAS UTILITIES
(BASED ON VALUE LINE LONG TERM EPS GROWTH RATES)

Company	Annualized Last Paid Dividend (1)	Average Monthly High/Low Prices Jan 2009-Mar 2009 (2)	Expected Dividend Yield [1/] (3)	Value Line EPS Growth (4)	DCF Cost of Equity [2/] (5)
AGL Resources	1.72	29.30	6.0	3.0	9.0
Consolidated Edison	2.36	38.41	6.2	1.0	7.2
Dominion Resources	1.75	32.69	5.9	10.5	16.4
Duke Energy	0.92	14.35	6.9	7.0	13.9
FPL	1.89	48.70	4.3	10.5	14.8
New Jersey Resources	1.24	36.57	3.6	5.5	9.1
Northwest Nat. Gas	1.58	42.36	4.0	7.0	11.0
NSTAR	1.50	32.61	4.9	7.5	12.4
Piedmont Natural Gas	1.08	25.89	4.5	7.5	12.0
Scana	1.88	32.05	6.1	4.0	10.1
Southern Co.	1.68	32.11	5.5	4.5	10.0
Vectren	1.34	22.87	6.2	6.0	12.2
WGL Holdings Inc.	1.42	32.05	4.6	4.0	8.6
Mean	**1.57**	**32.30**	**5.3**	**6.0**	**11.3**
Median	**1.58**	**32.11**	**5.5**	**6.0**	**11.0**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight and *Value Line* (Issue 1, February 27, 2009; Issue 3, March 13, 2009; Issue 5, March 27, 2009)

DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF U.S. ELECTRIC AND GAS UTILITIES (TWO-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Monthly High/Low Prices Jan 2009-Mar 2009	Stage 1 I/B/E/S EPS Forecasts	Stage 2 GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	29.30	4.3	5.0	10.9
Consolidated Edison	2.36	38.41	2.5	5.0	10.8
Dominion Resources	1.75	32.69	7.8	5.0	11.3
Duke Energy	0.92	14.35	4.5	5.0	11.6
FPL	1.89	48.70	9.6	5.0	9.9
New Jersey Resources	1.24	36.57	7.0	5.0	8.8
Northwest Nat. Gas	1.58	42.36	4.8	5.0	8.8
NSTAR	1.50	32.61	6.0	5.0	10.0
Piedmont Natural Gas	1.08	25.89	7.1	5.0	9.7
Scana	1.88	32.05	4.6	5.0	11.0
Southern Co.	1.68	32.11	5.4	5.0	10.5
Vectren	1.34	22.87	7.2	5.0	11.7
WGL Holdings Inc.	1.42	32.05	4.0	5.0	9.4
Mean	**1.57**	**32.30**	**5.7**	**5.0**	**10.3**
Median	**1.58**	**32.11**	**5.4**	**5.0**	**10.5**

1/ Forecast nominal rate of GDP growth, 2010-19
2/ Internal Rate of Return: average I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip *Economic Indicators* (March 2009); I/B/E/S (March 2009)

RISK MEASURES FOR 27 LOW RISK UNREGULATED CANADIAN COMPANIES

	Debt Ratings		CBS Stock	Beta				2007 Equity Ratio
				2003-2007		2004-2008		Based On
Company Name	S&P	DBRS	Rating	Raw	Adjusted	Raw	Adjusted	Total Capital
ANDREW PELLER LTD			Average	0.55	0.70	0.56	0.70	47.9%
ASTRAL MEDIA INC -CL A			Very Conservative	0.60	0.73	0.56	0.70	100.0%
CANADIAN NATIONAL RAILWAY CO	A-	A (low)	Very Conservative	0.97	0.98	0.46	0.64	64.4%
CANADIAN PACIFIC RAILWAY LTD	BBB	BBB	Very Conservative	0.70	0.80	0.69	0.79	55.3%
CANADIAN TIRE CORP -CL A	BBB+	A (low)	Very Conservative	0.84	0.89	0.53	0.68	65.9%
COGECO INC -SUB VTG			Very Conservative	0.60	0.73	1.01	1.01	27.0%
FINNING INTERNATIONAL INC	BBB+	A (low)	Conservative	0.83	0.88	1.03	1.02	57.6%
JEAN COUTU GROUP			Very Conservative	0.59	0.73	0.33	0.55	89.6%
LEON'S FURNITURE LTD			Average	0.59	0.72	0.71	0.80	99.9%
LINAMAR CORP			Conservative	0.69	0.79	1.22	1.15	65.3%
LOBLAW COMPANIES LTD	BBB	BBB	Very Conservative	0.73	0.82	0.22	0.48	54.1%
MAGNA INTERNATIONAL -CL A	BBB	A	Conservative	0.99	0.99	0.80	0.87	91.5%
MAPLE LEAF FOODS INC			Very Conservative	0.30	0.53	0.09	0.39	56.8%
METRO INC -CL A	BBB	BBB	Very Conservative	0.80	0.86	0.29	0.52	64.9%
NEWFOUNDLAND CAP CORP -CL A			Average	0.03	0.35	0.04	0.36	62.8%
REITMANS (CANADA) -CL A			Average	1.12	1.08	0.85	0.90	97.0%
RICHELIEU HARDWARE LTD			Average	0.41	0.60	0.39	0.59	96.8%
SAPUTO INC			Very Conservative	0.37	0.58	0.31	0.54	78.3%
SHAW COMMUNICATIONS INC-CL B	BBB-	BBB (low)	Very Conservative	0.40	0.59	0.41	0.60	39.4%
SNC-LAVALIN GROUP INC	BBB+	BBB (high)	Very Conservative	0.55	0.70	0.97	0.98	30.6%
THOMSON-REUTERS CORP (CDN)	A-	A (low)	Very Conservative	0.46	0.64	0.34	0.56	73.0%
TOROMONT INDUSTRIES LTD		BBB	Average	0.79	0.86	0.74	0.83	74.0%
TORSTAR CORP -CL B		BBB	Conservative	0.28	0.52	0.50	0.66	58.4%
TRANSCONTINENTAL INC -CL A	BBB	BBB (high)	Very Conservative	0.88	0.92	0.76	0.84	68.7%
TVA GROUP INC -CL B			Average	0.55	0.70	0.95	0.97	78.5%
UNI-SELECT INC			Average	0.42	0.61	0.43	0.62	70.4%
WESTON (GEORGE) LTD	BBB	BBB	Very Conservative	0.59	0.73	-0.22	0.18	32.7%
Mean	**BBB**	**BBB(high)**	**Conservative**	**0.61**	**0.74**	**0.55**	**0.70**	**66.7%**
Median	**BBB**	**BBB/BBB(high)**	**Very Conservative**	**0.59**	**0.73**	**0.53**	**0.68**	**65.3%**

Source: Standard and Poor's Research Insight, DBRS and *The Blue Book of CBS Stock Reports*.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
27 LOW RISK UNREGULATED CANADIAN COMPANIES

Company Name	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average 1991-2007
ANDREW PELLER LTD	10.1	9.3	9.0	10.0	12.3	13.8	13.1	10.3	18.7	6.2	7.9	9.8	12.4	10.1	6.9	10.2	11.5	10.7
ASTRAL MEDIA INC -CL A	6.3	4.8	5.8	7.0	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	13.0	7.0
CANADIAN NATIONAL RAILWAY CO	-0.4	-33.4	-3.2	9.7	-43.7	6.1	13.9	2.8	12.6	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	5.4
CANADIAN PACIFIC RAILWAY LTD	-12.6	-7.4	-3.1	6.1	-13.0	13.5	18.0	10.3	7.3	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	7.7
CANADIAN TIRE CORP -CL A	11.9	6.4	6.9	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	10.8
COGECO INC -SUB VTG	-2.4	0.7	21.9	6.8	3.0	0.0	10.8	11.3	25.1	3.5	25.3	12.5	2.9	-3.1	-6.3	7.4	21.0	8.3
FINNING INTERNATIONAL INC	1.1	0.7	6.5	14.9	16.3	16.0	16.2	0.5	8.7	10.5	14.1	15.5	14.0	10.1	12.0	13.4	17.2	11.0
JEAN COUTU GROUP	20.3	18.5	10.1	17.0	15.2	16.2	15.3	15.5	15.7	14.9	15.7	16.6	16.2	8.9	6.6	8.0	-14.3	12.7
LEON'S FURNITURE LTD	14.6	11.4	16.4	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	19.2	16.8
LINAMAR CORP	14.1	18.1	20.5	27.7	22.3	29.0	36.9	21.9	14.7	15.7	7.8	9.7	6.5	14.0	13.6	12.3	12.6	17.5
LOBLAW COMPANIES LTD	13.2	8.7	9.6	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	12.8
MAGNA INTERNATIONAL -CL A	6.6	22.8	19.6	21.7	21.8	15.8	21.6	12.3	12.0	15.9	14.7	11.8	9.5	13.3	10.5	7.7	7.8	14.4
MAPLE LEAF FOODS INC	8.8	7.9	7.3	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	19.2	8.5
METRO INC -CL A	6.1	7.3	13.0	16.2	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	15.1	18.6
NEWFOUNDLAND CAP CORP -CL A	-21.0	-39.8	17.7	19.4	8.6	9.0	62.1	45.1	4.7	3.3	-5.6	12.7	7.9	12.2	7.1	13.8	20.7	10.5
REITMANS (CANADA) -CL A	9.4	15.4	11.1	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	24.7	14.1
RICHELIEU HARDWARE LTD	NA	NA	NA	17.4	10.9	11.6	15.5	16.5	17.4	19.8	19.9	21.8	21.2	20.5	18.4	18.3	17.2	17.6
SAPUTO INC	NA	NA	NA	NA	NA	37.3	18.9	19.3	18.6	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	19.5
SHAW COMMUNICATIONS INC-CL B	12.9	11.5	11.5	10.2	6.2	11.8	2.9	-0.1	1.9	5.5	-8.4	-14.1	-4.5	2.8	7.7	27.2	20.4	6.2
SNC-LAVALIN GROUP INC	3.2	5.6	8.9	13.1	13.8	15.8	14.5	14.3	10.7	6.7	6.6	38.9	13.8	15.1	17.2	18.7	16.7	13.7
THOMSON-REUTERS CORP (CDN)	9.9	6.0	10.0	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	14.0
TOROMONT INDUSTRIES LTD	14.0	13.6	20.7	30.6	27.1	24.3	47.5	22.5	16.6	15.4	16.4	12.7	16.9	17.8	17.6	19.0	20.0	20.8
TORSTAR CORP -CL B	-0.6	8.4	-1.7	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3	9.5
TRANSCONTINENTAL INC -CL A	0.3	8.1	9.3	8.1	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	10.3	10.2
TVA GROUP INC -CL B	-17.9	2.1	9.4	0.3	9.2	10.4	15.0	20.5	19.8	16.4	-49.5	27.0	23.7	20.9	12.9	-1.7	19.4	8.1
UNI-SELECT INC	NA	NA	NA	24.7	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	13.7	18.2
WESTON (GEORGE) LTD	7.0	3.2	4.5	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	13.6
Mean	**4.8**	**4.6**	**10.1**	**12.9**	**9.4**	**13.3**	**19.1**	**14.8**	**14.5**	**12.8**	**8.8**	**15.0**	**13.6**	**13.9**	**12.9**	**12.5**	**15.5**	**12.5**
Median	**6.8**	**7.6**	**9.5**	**11.3**	**11.6**	**13.8**	**15.1**	**13.0**	**14.0**	**14.9**	**12.5**	**15.2**	**14.0**	**13.9**	**13.3**	**13.4**	**17.2**	**12.7**
Average of Annual Medians																		**12.8**

Source: Standard and Poor's Research Insight.

RISK MEASURES AND RETURNS ON EQUITY FOR 81 LOW RISK UNREGULATED U.S. COMPANIES

Company Name	S&P Debt Rating	Value Line Safety	Value Line Earnings Predictability	Value Line Financial Strength	Value Line Beta	Equity Ratio (Total Capital) 2006	Equity Ratio (Total Capital) 2007	Return on Average Common Equity 1991-2007	*Value Line* Forecast Return on Average Common Equity 2011-2013	1991-2007 Average Market To Book Ratio
3M CO	AA	1	80	A++	0.75	73%	70%	26.9	31.5	5.5
AARON RENTS INC		3	65	B++	0.80	82%	78%	13.1		2.0
ABM INDUSTRIES INC		3	90	B++	0.95	100%	100%	13.4	11.9	1.9
ACETO CORP		3	60	B++	0.85	100%	100%	10.1		1.4
ARDEN GROUP INC -CL A		3	65	B++	0.55	98%	99%	15.7		2.3
BOB EVANS FARMS		3	55	B++	0.90	77%	67%	11.4	12.2	1.8
BROWN-FORMAN -CL B	A	1	100	A+	0.70	57%	63%	24.0	20.1	4.5
CASEYS GENERAL STORES INC		3	70	B	0.75	70%	75%	11.9	12.9	2.1
CATO CORP -CL A		3	65	B++	0.95	100%	100%	18.1	18.8	2.6
CLARCOR INC		3	100	B++	0.95	97%	97%	17.2	13.7	2.7
COCA-COLA ENTERPRISES INC	A	3	5	B	0.90	31%	38%	4.9	12.8	2.8
CONAGRA FOODS INC	BBB+	2	75	A	0.65	57%	57%	17.1	16.4	3.4
COURIER CORP		3	65	B+	0.95	91%	92%	11.9		1.5
CSS INDUSTRIES INC		3	75	B+	0.95	90%	93%	13.2		1.4
CVS CAREMARK CORP	BBB+	2	95	A	0.80	65%	75%	10.4	11.7	3.2
ENNIS INC		3	95	B++	0.95	78%	79%	19.8		2.5
FAMILY DOLLAR STORES		3	90	A	0.60	83%	82%	19.0	15.9	3.5
FARMER BROS CO		3	10	B++	0.95	100%	100%	8.2		1.4
FEDEX CORP	BBB+	2	80	B++	0.85	83%	88%	11.7	14.5	2.3
FLEXSTEEL INDUSTRIES INC		3	45	B+	0.40	77%	80%	7.8		1.1
FLOWERS FOODS INC	BBB-	3	60	B	0.70	87%	96%	9.4	16.6	2.7
FORTUNE BRANDS INC	BBB+	2	85	B++	0.95	45%	56%	13.1	10.3	2.3
FRISCH'S RESTAURANTS INC		3	70	B++	0.65	73%	77%	9.5		1.4
G&K SERVICES INC -CL A		3	90	B+	0.85	72%	73%	12.8	7.2	2.7
GENERAL DYNAMICS CORP	A	1	100	A++	0.90	78%	81%	24.6	18.0	2.8
GENUINE PARTS CO		1	100	A++	0.80	84%	84%	17.9	21.2	2.9
HASBRO INC	BBB+	3	40	B++	0.80	75%	62%	10.9	21.0	2.2
HAVERTY FURNITURE		3	40	B	0.75	85%	91%	8.9		1.2
HEALTHCARE SERVICES GROUP		3	90	B++	0.75	100%	100%	9.4		2.0
HEARTLAND EXPRESS INC		3	75	B++	0.85	100%	100%	19.8	16.9	4.1
HOME DEPOT INC	BBB+	1	75	A++	0.95	68%	57%	19.7	15.1	5.8
HORMEL FOODS CORP	A	1	100	A	0.70	84%	82%	16.8	13.5	2.8
ILLINOIS TOOL WORKS	AA-	1	100	A++	0.95	86%	80%	18.6	22.2	3.5
INTL SPEEDWAY CORP -CL A	BBB+	3	85	B+	0.90	76%	75%	17.1	10.6	3.4
KIMBERLY-CLARK CORP	A	1	100	A++	0.55	63%	49%	25.2	35.9	5.2
LANCASTER COLONY CORP		1	90	A+	0.75	98%	90%	21.1	19.8	3.1
LANCE INC		3	55	B+	0.75	82%	83%	11.6	14.2	2.7
LOCKHEED MARTIN CORP	A-	1	90	A++	0.80	61%	69%	14.4	32.6	2.9
MATTEL INC	BBB-	3	80	B++	0.85	78%	71%	19.7	29.7	4.2
MATTHEWS INTL CORP -CL A		3	100	B+	0.90	73%	72%	19.3	17.3	3.3
MCCORMICK & COMPANY INC	A-	2	100	A	0.60	59%	60%	24.8	23.4	5.1

RISK MEASURES AND RETURNS ON EQUITY FOR 81 LOW RISK UNREGULATED U.S. COMPANIES

Company Name	S&P Debt Rating	Value Line Safety	Value Line Earnings Predictability	Value Line Financial Strength	Value Line Beta	Equity Ratio (Total Capital) 2006	Equity Ratio (Total Capital) 2007	Return on Average Common Equity 1991-2007	*Value Line* Forecast Return on Average Common Equity 2011-2013	1991-2007 Average Market To Book Ratio
MCDONALD'S CORP	A	1	90	A++	0.75	65%	62%	17.9	30.2	3.6
MEREDITH CORP		2	80	B++	0.90	55%	64%	18.7	12.9	3.7
MOLSON COORS BREWING CO	BBB+	3	NMF	B+	0.55	73%	76%	8.2	9.6	1.6
MULTI-COLOR CORP		3	75	B+	0.95	93%	48%	8.1		3.0
NIKE INC -CL B	A+	1	95	A+	0.90	93%	93%	21.2	23.4	3.9
NORTHROP GRUMMAN CORP	BBB+	1	85	A+	0.75	79%	80%	10.9	12.4	1.5
OMNICOM GROUP	A-	2	100	B++	0.95	56%	57%	24.3	28.3	5.6
OTTER TAIL CORP	BBB-	2	75	A	0.90	61%	53%	14.1	9.6	2.1
PEPSIAMERICAS INC	A	3	85	B	0.85	49%	46%	11.8	13.5	2.9
PEPSICO INC	A+	1	100	A++	0.60	85%	79%	29.4	31.1	7.0
PROCTER & GAMBLE CO	AA-	1	100	A++	0.55	62%	65%	26.7	17.9	6.2
RAYTHEON CO	A-	1	65	A+	0.70	74%	85%	9.8	14.6	1.7
ROLLINS INC		3	90	B++	0.80	100%	99%	23.1	28.0	6.4
ROSS STORES INC	BBB+	3	85	A	0.90	86%	87%	25.9	29.2	3.7
RUDDICK CORP		3	95	B+	0.60	73%	73%	11.3	11.8	1.7
SEABOARD CORP		3	5	B++	0.90	82%	86%	11.8		1.1
SHERWIN-WILLIAMS CO	A-	2	95	A	0.75	69%	65%	19.7	23.9	3.2
SMITH (A O) CORP		3	60	B+	0.90	61%	66%	12.2	10.5	1.5
SMUCKER (JM) CO		2	90	A	0.65	81%	70%	11.7	11.1	2.2
SOUTHWEST AIRLINES	BBB+	3	55	B+	0.90	79%	77%	12.4	9.7	2.7
STANDEX INTERNATIONAL CORP		3	70	B+	0.95	63%	55%	16.1	13.9	2.2
SYSCO CORP	AA-	1	95	A++	0.65	63%	65%	26.1	37.5	6.2
TANDY BRANDS ACCESSORIES INC		3	10	B+	0.65	88%	95%	9.3		1.3
TOOTSIE ROLL INDUSTRIES INC		1	90	A+	0.70	99%	99%	15.1	7.3	3.5
UNIFIRST CORP		3	90	B+	0.80	68%	71%	11.3	10.2	1.7
UNITED PARCEL SERVICE INC	AA-	1	95	A	0.75	79%	53%	20.5	37.2	5.9
UNITED TECHNOLOGIES CORP	A	1	100	A++	0.95	69%	70%	18.1	17.1	3.4
UNIVERSAL CORP/VA	BBB-	3	50	B++	0.75	47%	55%	15.5	11.2	1.9
VF CORP	A-	2	100	A	0.95	80%	74%	17.0	16.9	2.3
VILLAGE SUPER MARKET -CL A		3	90	B++	0.75	82%	86%	7.3		0.7
WALGREEN CO	A+	1	100	A+	0.75	94%	90%	19.0	15.1	5.7
WAL-MART STORES INC	AA	1	100	A++	0.60	61%	59%	21.9	18.9	5.0
WASHINGTON POST -CL B	A+	1	55	A+	0.85	88%	87%	14.9	7.1	3.1
WASTE MANAGEMENT INC	BBB+	2	100	A	0.85	43%	41%	10.8	21.1	3.4
WD-40 CO		3	85	B++	0.80	71%	76%	34.8	19.8	5.9
WEIS MARKETS INC		1	80	A	0.65	100%	100%	9.7	9.1	1.7
WERNER ENTERPRISES INC		3	80	B++	0.90	90%	100%	12.1	12.8	2.0
WEYCO GROUP INC		3	80	B++	0.90	93%	100%	14.0		1.5
WILEY (JOHN) & SONS -CL A		3	95	B+	0.90	35%	45%	21.8	19.5	4.7
WOLVERINE WORLD WIDE		3	100	A	0.80	96%	98%	11.5	16.8	2.2
Mean	**A-**	**2**	**79**	**A**	**0.80**	**77%**	**76%**	**15.9**	**17.8**	**3.0**
Median	**A-**	**3**	**85**	**B++**	**0.80**	**78%**	**77%**	**14.9**	**16.4**	**2.7**
Average of Annual Medians								**15.7**		

Source: Standard and Poor's Research Insight, *Value Line* (www.valueline.com, February 27, 2009 and various issues)

COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS
FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities			U.S. Gas Utilities		U.S. Electric Utilities	
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Equity Risk Premium	Allowed ROE	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.62	4.07	12.67	4.05	12.70	4.08
1991	13.56	9.72	3.85	12.51	8.09	4.43	12.46	4.38	12.55	4.47
1992	12.94	8.68	4.26	12.06	7.68	4.39	12.01	4.34	12.09	4.42
1993	12.16	7.86	4.30	11.37	6.58	4.79	11.35	4.77	11.41	4.83
1994	11.50	8.69	2.81	11.34	7.41	3.93	11.35	3.94	11.34	3.93
1995	12.13	8.41	3.72	11.51	6.81	4.70	11.43	4.62	11.55	4.74
1996	11.36	7.75	3.62	11.29	6.72	4.57	11.19	4.47	11.39	4.67
1997	10.84	6.66	4.18	11.34	6.57	4.77	11.29	4.72	11.40	4.83
1998	10.15	5.59	4.56	11.59	5.53	6.06	11.51	5.98	11.66	6.13
1999	9.50	5.72	3.78	10.74	5.91	4.83	10.66	4.75	10.77	4.86
2000	9.79	5.71	4.08	11.41	5.88	5.53	11.39	5.51	11.43	5.55
2001	9.68	5.77	3.92	11.05	5.47	5.58	10.95	5.48	11.09	5.62
2002	9.62	5.67	3.95	11.10	5.41	5.69	11.03	5.62	11.16	5.75
2003	9.73	5.31	4.42	10.98	5.03	5.95	10.99	5.96	10.97	5.94
2004	9.59	5.11	4.48	10.66	5.09	5.56	10.59	5.50	10.73	5.64
2005	9.51	4.38	5.13	10.50	4.52	5.98	10.46	5.94	10.54	6.02
2006	9.02	4.26	4.76	10.39	4.87	5.52	10.44	5.57	10.36	5.49
2007	8.66	4.30	4.37	10.30	4.80	5.51	10.24	5.44	10.36	5.56
2008	8.77	4.04	4.73	10.42	4.22	6.20	10.37	6.15	10.46	6.24
Means:										
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**4.38**	**12.19**	**4.45**
1994-1997	**11.46**	**7.88**	**3.58**	**11.37**	**6.88**	**4.49**	**11.32**	**4.44**	**11.42**	**4.54**
1998-2008	**9.46**	**5.08**	**4.38**	**10.83**	**5.16**	**5.67**	**10.78**	**5.63**	**10.87**	**5.71**

1/ 2008 ROE represents results for the entire year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Canadian regulatory decisions; Bank of Canada; Federal Reserve; U.S. Treasury.

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date (1)	Regulator (2)	Order/ File Number (3)	Debt (4)	Preferred Stock (5)	Common Stock Equity (6)	Equity Return (7)	Forecast 30-Year Bond Yield (8)
Electric Utilities								
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55
ATCO Electric		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55
EPCOR		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55
FortisBC Inc.	3/06; 11/08	BCUC	G-14-06; L-55-08	60.00	0.00	40.00	8.87	4.35
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	2/09	IRAC	UE-09-02	59.50	0.00	40.50	9.75	na
Newfoundland Power	12/07	NLPub	P.U.32 (2007)	54.01	1.15	44.84	8.95	4.60
Nova Scotia Power	1/05;11/08	NSUARB	2005 NSUARB 27; 2008 NSUARB 140	53.30	9.20	37.50	9.35	na
Ontario Electricity Distributors	12/06;2/09	OEB	Report of the Board	60.00	0.00	40.00	8.01 1/	3.71
Ontario Power Generation	11/08	OEB	EB-2007-0905	53.00	0.00	47.00	8.65	4.75
Gas Distributors								
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23
Gazifere	2/01; 12/08	Régie	D-2008-153; D-2001-55	60.00	0.00	40.00	8.82	4.13
Gaz Metropolitain	11/08	Régie	D-2008-140	54.00	7.50	38.50	8.76	4.56
Pacific Northern Gas	5/07; 11/08	BCUC	G-55-07; L-55-08	56.20	3.80	40.00	9.12	4.35
Terasen Gas 2/	3/06; 11/08	BCUC	G-14-06; L-55-08	64.99	0.00	35.01	8.47	4.35
Terasen Gas (Vancouver Island)	3/06; 11/08	BCUC	G-14-06; L-55-08	65.00	0.00	40.00	9.17	4.35
Union Gas	1/04; 6/06; 1/08	OEB	RP-2002-0158; EB-2005-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23
Gas Pipelines								
Foothills Pipe Lines (Yukon) Ltd.	12/05; 11/08	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.57	4.35
TCPL-BC System	2/06; 11/08	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.57	4.35
TransCanada PipeLines	11/08; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.57	4.35
Trans Quebec & Maritimes Pipeline 3/	3/09	NEB	RH-1-2008	60.00	0.00	40.00	9.70	4.35
Westcoast Energy	12/06; 11/08	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.57	4.35

1/ The OEB has initiated a process to review the reasonableness of the 2009 cost of capital values.
2/ The equity ratio reflects the impact of the amalgamation of TGI and Squamish Gas.
3/ The NEB approved an after-tax weighted average cost of capital of 6.4%. The ROE of 9.7% and 40% equity ratio represent equivalent values cited by the NEB to facilitate comparisons.

Source: Canadian regulatory decisions.

**RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR CANADIAN UTILITIES**

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Electric Utilities																				
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	na
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[1/]	[1/]	[1/]	[1/]	[1/]	[1/]	9.40	9.60	9.50	8.93	8.51	8.75	na
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	na
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	na	9.35
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[1/]	[2/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	na	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.80**
Gas Distributors																				
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	na
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**8.96**	**8.59**	**8.77**	**8.66**
Gas Pipelines (NEB)																				
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.71	8.57
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.71	8.57
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.71**	**8.57**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.02**	**8.66**	**8.77**	**8.69**

[1/] Negotiated settlement, details not available.
[2/] Negotiated settlement, implicit ROE made public is 10.5%.

Source: Canadian regulatory decisions

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES

Company	Average Monthly High/Low Prices Jan 2009-Mar 2009 (1)	Book Value Per Share Year End 2008 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Total Capital Common Equity Ratio Year End 2008 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
CANADIAN UTILITIES -CL A	39.39	21.92	1.80	41.2%	55.8%	44.2%
EMERA INC	20.79	13.78	1.51	40.7%	50.9%	49.1%
ENBRIDGE INC	39.28	17.41	2.26	34.4%	54.1%	45.9%
FORTIS INC	23.44	18.00	1.30	31.6%	37.6%	62.4%
TRANSCANADA CORP	32.01	20.92	1.53	39.1%	49.5%	50.5%
Mean				**37.4%**	**49.6%**	**50.4%**

Sources: Standard & Poor's Research Insight

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: CANADIAN UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)

ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	CAPM Cost of Equity
	=	8.75%
Tax Rate	=	32.0%
CEQ Ratio	(1)	49.6%
Debt Ratio	(1)	50.4%
CEQ Ratio	(2)	37.4%
Debt Ratio	(2)	62.6%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 49.6%)

   $WACC_{AT}$ = (6.625%)(1-.320)(50.4%) + (8.75%)(49.6%)

   = 6.61%

2. Estimate Cost of Equity for sample at 37.4% common equity ratio with $WACC_{AT}$ unchanged at 6.61%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

   6.61% = (6.625%)(1-.320)(62.6%) + (X)(37.4%)

   Cost of Equity at 37.4% Equity Ratio = 10.13%

3. Difference between Equity Return at 49.6% and 37.4% common equity ratios:

   10.13% - 8.75% = 1.38% (138 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Cost of Equity
	=	8.75%
Tax Rate	=	32.0%
CEQ Ratio	(1)	49.6%
Debt Ratio	(1)	50.4%
CEQ Ratio	(2)	37.4%
Debt Ratio	(2)	62.6%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 49.6%)

$WACC_{AT}$ = (6.625%)(1-.320)(50.4%) + (8.75%)(49.6%)
= 6.61%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 37.4%)

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 6.61\% \times \frac{(1-.320 \times 62.6\%)}{(1-.320 \times 50.4\%)}$$

$WACC_{AT(ML)}$ = 6.30%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{ML}$) + (Equity Cost)(Equity $Ratio_{ML}$)
6.30% = (6.625%)(1-.320)(62.6%) + (X)(37.4%)
Cost of Equity at 37.4% Equity Ratio = 9.31%

4. Difference between Equity Return at 49.6% and 37.4% common equity ratios:

9.31% - 8.75% = 0.56% (56 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
55-140 Basis Points (Midpoint of 100)

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES

Company	Average Monthly High/Low Prices Jan 2009-Mar 2009 (2)	Book Value Per Share Year End 2008 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Total Capital Common Equity Ratio 2008 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
AGL RESOURCES INC	29.30	21.48	1.36	39.4%	47.0%	53.0%
CONSOLIDATED EDISON INC	38.41	35.43	1.08	48.5%	50.5%	49.5%
DOMINION RESOURCES INC	32.69	17.28	1.89	36.3%	51.9%	48.1%
DUKE ENERGY CORP	14.35	16.50	0.87	59.2%	55.8%	44.2%
FPL GROUP INC	48.70	28.57	1.70	40.6%	53.8%	46.2%
NEW JERSEY RESOURCES CORP	36.57	17.29	2.12	51.2%	68.9%	31.1%
NORTHWEST NATURAL GAS CO	42.36	23.71	1.79	45.3%	59.6%	40.4%
NSTAR	32.61	16.74	1.95	36.8%	53.2%	46.8%
PIEDMONT NATURAL GAS CO	25.89	12.11	2.14	41.9%	60.6%	39.4%
SCANA CORP	32.05	25.81	1.24	39.3%	44.6%	55.4%
SOUTHERN CO	32.11	17.07	1.88	40.5%	56.2%	43.8%
VECTREN CORP	22.87	16.69	1.37	42.2%	50.1%	49.9%
WGL HOLDINGS INC	32.05	20.99	1.53	51.7%	62.0%	38.0%
Mean				**44.1%**	**54.9%**	**45.1%**

Sources: Schedule 16 for stock prices, Standard & Poor's Research Insight

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: U.S. UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)

ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Midpoint of DCF-Based Risk Premium and DCF Cost of Equity Test Results
	=	10.25%
Tax Rate	=	32.0%
CEQ Ratio	(1)	54.9%
Debt Ratio	(1)	45.1%
CEQ Ratio	(2)	44.1%
Debt Ratio	(2)	55.9%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 54.9%)

   $WACC_{AT}$ = (6.625%)(1-.320)(45.1%) + (10.25%)(54.9%)

   = 7.66%

2. Estimate Cost of Equity for sample at 44.1% common equity ratio with $WACC_{AT}$ unchanged at 7.66%

   Tax Rate Declines to Canadian Level

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

   7.66% = (6.625%)(1-.320)(55.9%) + (X)(44.1%)

   Cost of Equity at 44.1% Equity Ratio = 11.66%

3. Difference between Equity Return at 54.9% and 44.1% common equity ratios:

   11.66% - 10.25% = 1.41% (141 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Cost of Equity
	=	10.25%
Tax Rate	=	28.5%
CEQ Ratio	(1)	54.9%
Debt Ratio	(1)	45.1%
CEQ Ratio	(2)	44.1%
Debt Ratio	(2)	55.9%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 54.9%)

   $WACC_{AT}$ = (6.625%)(1-.285)(45.1%) + (10.25%)(54.9%)
   = 7.76%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 44.1%)
   Tax Rate Declines to Canadian Level

   $WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

   $$WACC_{AT(ML)} = 7.76\% \times \frac{(1-.29 \times 55.9\%)}{(1-.285 \times 45.1\%)}$$

   $WACC_{AT(ML)}$ = 7.49%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

   $WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{ML}$) + (Equity Cost)(Equity $RatioM_{LL}$)
   7.49% = (6.625%)(1-.29)(55.9%) + (X)(44.1%)
   Cost of Equity at 44.1% Equity Ratio = 10.98%

4. Difference between Equity Return at 54.9% and 44.1% common equity ratios:
   10.98% - 10.25% = 0.73% (73 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE AND TAX RATE ON COST OF EQUITY
Approximately 75 to 140 basis points (Midpoint of 110)