VOLUME 2: EXHIBITS & SUPPORTING MATERIALS

A. EXHIBITS

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VOLUME 3: EXPERT EVIDENCE & STUDIES

1. Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc.
2. Depreciation Study: Mr. John Wiedmayer, Gannett Fleming, Valuation and Rate Consultants, LLC

Newfoundland Power Inc.

Operating Costs by Function
2013 to 2017F
($000s)

	Function	**Actual 2013**	**Actual 2014**	**Forecast 2015**	**Forecast 2016**	**Forecast 2017**
1	Distribution	9,226	8,994	8,668	9,053	9,321
2	Transmission	928	1,289	1,025	1,050	1,075
3	Substations	2,629	2,627	2,624	2,734	2,814
4	Power Produced	2,877	2,985	2,918	3,038	3,125
5	Administrative & Engineering Support	6,866	8,248	7,370	7,696	7,922
6	Telecommunications	1,418	1,552	1,438	1,370	1,399
7	Environment	243	210	288	292	300
8	Fleet Operations & Maintenance	1,885	1,912	1,781	1,728	1,619
9						
10	**Electricity Supply**	**26,072**	**27,817**	**26,112**	**26,961**	**27,575**
11						
12	Customer Services	9,458	9,750	9,041	9,344	9,115
13	Conservation	717	802	767	778	801
14	Uncollectible Bills	897	1,490	1,300	1,327	1,355
15						
16	**Customer Services**	**11,072**	**12,042**	**11,108**	**11,449**	**11,271**
17						
18	Information Systems	3,175	3,370	3,601	3,891	4,031
19	Financial Services	1,707	1,751	1,821	1,885	1,944
20	Corporate & Employee Services	13,243	13,400	13,585	14,311	13,999
21	Insurances	1,197	1,243	1,249	1,258	1,284
22						
23	**General**	**19,322**	**19,764**	**20,256**	**21,345**	**21,258**
24						
25	**Gross Operating Cost**	**56,466**	**59,623**	**57,476**	**59,755**	**60,104**

Newfoundland Power Inc.

Operating Costs by Breakdown
2013 to 2017F
($000s)

		Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
1	Regular and standby	$ 28,735	$ 29,678	$ 29,457	$ 30,258	$ 31,242
2	Temporary	2,554	2,437	1,998	2,040	1,599
3	Overtime	2,615	3,394	2,442	2,817	2,908
4	**Total Labour**	**33,904**	**35,509**	**33,897**	**35,115**	**35,749**
5						
6	Vehicle Expenses	1,881	1,901	1,775	1,721	1,611
7	Operating Materials	1,568	1,841	1,628	1,662	1,697
8	Inter-Company Charges	53	41	50	50	50
9	Plants, Subs, System Oper & Bldgs	2,153	2,312	2,251	2,298	2,346
10	Travel	1,278	1,277	1,040	1,198	1,223
11	Tools and Clothing Allowance	1,141	1,191	1,124	1,147	1,171
12	Miscellaneous	1,476	1,430	1,376	1,405	1,435
13	Taxes and Assessments	1,011	1,040	1,125	1,164	1,189
14	Uncollectible Bills	897	1,490	1,300	1,327	1,355
15	Insurance	1,197	1,243	1,256	1,258	1,284
16	Severance & Other Employee Costs	84	58	72	74	75
17	Education, Training, Employee Fees	390	292	300	341	350
18	Trustee and Directors' Fees	397	431	463	473	483
19	Other Company Fees	1,820	2,222	2,274	2,689	2,053
20	Stationery & Copying	308	266	277	283	289
21	Equipment Rental/Maintenance	677	769	797	813	831
22	Telecommunications	1,622	1,710	1,672	1,608	1,641
23	Postage	1,452	1,508	1,551	1,553	1,586
24	Advertising	365	388	364	460	469
25	Vegetation Management	1,993	1,789	1,812	1,850	1,889
26	Computing Equipment & Software	799	915	1,072	1,266	1,328
27	**Total Other**	**22,562**	**24,114**	**23,579**	**24,640**	**24,355**
28						
29	**Gross Operating Cost**	**$ 56,466**	**$ 59,623**	**$ 57,476**	**$ 59,755**	**$ 60,104**

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Income
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Revenue from rates	586,904	619,504	639,673	661,775	665,246
2	Excess earnings	(68)	-	-	-	-
3	Transfers from (to) the RSA	10,436	4,039	7,795	6,481	3,885
4		597,272	623,543	647,468	668,256	669,131
5						
6	Purchased power expense	392,928	404,550	425,670	449,006	450,829
7	Amortization of weather normalization reserve	(2,335)	(2,335)	(2,335)	-	-
8	Demand management incentive account adjustments	(383)	628	-	-	-
9		390,210	402,843	423,335	449,006	450,829
10						
11	Contribution	207,062	220,700	224,133	219,250	218,302
12						
13	Other revenue	7,445	5,570	4,911	4,842	4,770
14						
15	Other expenses:					
16	Operating expenses[1]	53,641	56,927	54,819	58,123	59,770
17	Employee future benefit costs	25,624	24,244	26,393	22,176	17,892
18	Deferred cost recoveries and amortizations	(768)	3,990	3,990	-	-
19	Depreciation	46,964	49,288	51,941	54,634	57,640
20	Finance charges	35,624	35,791	35,370	35,369	36,668
21		161,085	170,240	172,513	170,302	171,970
22						
23	Income Before Income Taxes	53,422	56,030	56,531	53,790	51,102
24	Income taxes[1]	14,866	16,201	16,210	15,486	14,889
25						
26	Net Income	38,556	39,829	40,321	38,304	36,213
27	Preferred Dividends	563	557	552	552	552
28						
29	Earnings applicable to Common Shares[1]	37,993	39,272	39,769	37,752	35,661
30						
31	**Rate of Return and Credit Metrics**					
32	Rate of Return on Rate Base (percentage)	8.10%	7.83%	7.45%	6.96%	6.61%
33	Regulated Return on Book Equity (percentage)	9.16%	9.15%	8.82%	7.96%	7.22%
34	Interest Coverage (times)	2.3	2.3	2.3	2.2	2.1
35	CFO Pre-W/C + Interest / Interest (times)	3.9	3.6	3.8	3.9	3.8
36	CFO Pre-W/C / Debt (percentage)	20.1%	17.5%	17.5%	17.5%	16.9%

[1] Shown after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Retained Earnings
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Balance - Beginning	323,886	351,279	366,426	395,088	412,393
2	Net income for the period	49,920	37,840	38,466	36,181	33,921
3	Allocation of Part VI.1 tax	741	981	252	252	252
4		374,547	390,100	405,144	431,521	446,566
5						
6	Dividends					
7	Preference shares	563	557	552	552	552
8	Common shares	22,705	23,117	9,504	18,576	11,559
9		23,268	23,674	10,056	19,128	12,111
10	Balance - End of Period	351,279	366,426	395,088	412,393	434,455

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Balance Sheets
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	**Assets**					
2	**Current assets**					
3	Cash	$ 159	$ -	$ -	$ -	$ -
4	Accounts receivable	90,499	82,073	92,928	93,863	93,712
5	Income taxes receivable	1,391	3,593	-	-	-
6	Materials and supplies	1,228	1,315	1,316	1,343	1,371
7	Prepaid expenses	1,080	1,315	1,316	1,343	1,371
8	Regulatory assets	31,891	29,726	21,020	18,256	15,132
9		126,248	118,022	116,580	114,805	111,586
10						
11	**Property, plant and equipment**	914,948	984,268	1,032,642	1,087,983	1,144,158
12	**Intangible assets**	15,412	16,064	19,600	22,777	24,465
13	**Regulatory assets**	340,359	327,793	316,604	299,326	292,733
14	**Defined benefit pension plans**	-	-	-	14,948	20,115
15	**Other assets**	4,249	3,848	4,005	4,186	3,973
16		$ 1,401,216	$ 1,449,995	$ 1,489,431	$ 1,544,025	$ 1,597,030
17						
18						
19	**Liabilities and Shareholders' Equity**					
20	**Current Liabilities**					
21	Short-term borrowings	$ -	$ 3,843	$ -	$ -	$ -
22	Accounts payable and accrued charges	81,905	80,443	84,122	87,045	87,625
23	Interest payable	7,786	6,444	6,764	6,738	6,460
24	Defined benefit pension plans	248	244	239	233	227
25	Other post employment benefits	3,239	2,695	2,971	3,377	3,667
26	Regulatory liabilities	2,335	2,335	-	-	-
27	Current installments of long-term debt	34,453	70,000	36,250	6,600	6,600
28	Deferred income taxes	4,732	6,111	4,984	4,984	4,984
29		134,698	172,115	135,330	108,977	109,563
30						
31	**Regulatory liabilities**	135,507	136,053	139,400	146,058	151,809
32	**Defined benefit pension plans**	6,366	14,706	310	-	-
33	**Other post employment benefits**	93,381	82,548	84,881	86,989	88,984
32	**Other liabilities**	840	660	700	700	700
33	**Deferred income taxes**	116,208	120,083	125,143	124,474	125,743
34	**Long-term debt**	483,635	478,135	529,310	585,165	606,507
35						
36						
37						
38	**Shareholders' Equity**					
39	**Common shares**	70,321	70,321	70,321	70,321	70,321
40	**Preference shares**	8,981	8,948	8,948	8,948	8,948
41	**Retained earnings**	351,279	366,426	395,088	412,393	434,455
42		430,581	445,695	474,357	491,662	513,724
43		$ 1,401,216	$ 1,449,995	$ 1,489,431	$ 1,544,025	$ 1,597,030

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Cash Flows
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	**Cash From (Used In) Operating Activities**					
2	Net Earnings	$ 49,920	$ 37,840	$ 38,466	$ 36,181	$ 33,921
3						
4	**Items not affecting cash:**					
5	Amortization of property, plant and equipment	48,839	51,376	54,191	56,760	59,623
6	Amortization of intangible assets and other	2,763	2,760	2,859	3,187	3,562
7	Change in long-term regulatory assets and liabilities	6,973	7,618	1,279	1,953	3,722
8	Income tax liability	(12,814)	-	-	-	-
9	Deferred income taxes	(878)	(241)	(1,550)	(669)	1,269
10	Employee future benefits	(61)	(1,767)	5,048	7,615	2,627
11	Other	(204)	322	(185)	(230)	(238)
12		94,538	97,908	100,108	104,797	104,486
13						
14	Change in non-cash working capital	(3,754)	4,692	(430)	1,097	879
15		90,784	102,600	99,678	105,894	105,365
16						
17	**Investing Activities**					
18	Capital expenditures	(88,655)	(113,438)	(100,190)	(109,920)	(113,052)
19	Intangible asset expenditures	(3,134)	(3,158)	(6,150)	(6,145)	(5,037)
20	Contributions from customers and security deposits	2,727	3,687	3,500	3,500	3,500
21	Other	72	47	40	-	-
22		(88,990)	(112,862)	(102,800)	(112,565)	(114,589)
23						
24	**Financing Activities**					
25	Change in short-term borrowings	(685)	3,843	(3,843)	-	-
26	Net proceeds (repayment) of committed credit facility	(42,000)	64,500	(51,327)	(12,551)	27,935
27	Proceeds from long-term debt	70,000	-	75,000	75,000	-
28	Repayment of long-term debt	(5,200)	(34,453)	(6,250)	(36,250)	(6,600)
29	Proceeds from related party loan	33,000	240,000	15,000	-	-
30	Repayment of related party loan	(33,000)	(240,000)	(15,000)	-	-
31	Payment of debt financing costs	(382)	(80)	(402)	(400)	-
32	Redemption of preference shares	(100)	(33)	-	-	-
33	Dividends					
34	Preference Shares	(563)	(557)	(552)	(552)	(552)
35	Common Shares	(22,705)	(23,117)	(9,504)	(18,576)	(11,559)
36		(1,635)	10,103	3,122	6,671	9,224
37						
38	**Change in Cash**	159	(159)	-	-	-
39	**Cash (Bank Indebtedness), Beginning of Year**	-	159	-	-	-
40	**Cash (Bank Indebtedness), End of Year**	$ 159	$ -	$ -	$ -	$ -

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Average Rate Base[1]
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Plant Investment	826,099	879,631	936,173	987,712	1,043,286
2						
3	Additions to Rate Base					
4	Defined Benefit Pension Costs	100,636	102,549	101,371	95,025	89,552
5	Credit Facility Costs	120	36	64	48	32
6	Cost Recovery Deferral - Seasonal Rates	94	82	69	55	42
7	Cost Recovery Deferral - Hearing Costs	322	483	161	-	-
8	Cost Recovery Deferral - Regulatory Amortizations	2,767	1,661	554	-	-
9	Cost Recovery Deferral - 2012 Cost of Capital	1,472	883	294	-	-
10	Cost Recovery Deferral - 2013 Revenue Shortfall	1,126	1,689	563	-	-
11	Cost Recovery Deferral - Conservation	1,156	3,511	6,650	10,014	13,227
12	Customer Finance Programs	1,405	1,249	1,136	1,136	1,136
13		109,098	112,143	110,862	106,278	103,989
14						
15	Deductions from Rate Base					
16	Weather Normalization Reserve	4,931	3,349	302	(518)	-
17	Other Post Employee Benefits	19,066	27,975	35,867	42,656	48,947
18	Customer Security Deposits	846	750	680	700	700
19	Accrued Pension Obligation	4,173	4,480	4,804	5,149	5,513
20	Future Income Taxes	2,189	2,201	2,134	1,999	3,400
21	Demand Management Incentive Account	143	87	223	-	-
22	Excess Earnings	-	25	48	48	48
23		31,348	38,867	44,058	50,034	58,608
24						
25	Average Rate Base Before Allowances	903,849	952,907	1,002,977	1,043,956	1,088,667
26						
27	Cash Working Capital Allowance	6,526	6,404	6,770	7,096	7,124
28						
29	Materials and Supplies Allowance	5,445	5,619	6,252	6,514	6,650
30						
31	Average Rate Base At Year End	915,820	964,930	1,015,999	1,057,566	1,102,441

[1] All amounts shown are averages.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Weighted Average Cost of Capital
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	**Average Capitalization**					
2	Debt	504,185	532,234	555,979	575,703	599,493
3	Preference Shares	9,031	8,965	8,948	8,948	8,948
4	Common Equity	414,578	429,174	451,079	474,060	493,739
5		927,794	970,373	1,016,006	1,058,711	1,102,180
6	**Average Capital Structure**					
7	Debt	54.35%	54.85%	54.72%	54.38%	54.39%
8	Preference Shares	0.97%	0.92%	0.88%	0.84%	0.81%
9	Common Equity	44.68%	44.23%	44.40%	44.78%	44.80%
10		100.00%	100.00%	100.00%	100.00%	100.00%
11						
12						
13	**Cost of Capital**					
14	Debt[1]	7.06%	6.72%	6.36%	6.14%	6.11%
15	Preference Shares	6.23%	6.21%	6.17%	6.17%	6.17%
16	Common Equity	9.16%	9.15%	8.82%	7.96%	7.22%
17						
18						
19	**Weighted Average Cost of Capital**					
20	Debt	3.84%	3.69%	3.48%	3.34%	3.32%
21	Preference Shares	0.06%	0.06%	0.05%	0.05%	0.05%
22	Common Equity	4.09%	4.05%	3.92%	3.57%	3.24%
23		7.99%	7.80%	7.45%	6.96%	6.61%

[1] Cost of debt is shown net of AFUDC. This is consistent with the cost of debt used in the calculation of return on rate base. For regulatory reporting purposes, the embedded cost of debt shown in Return 25 of the 2013 and 2014 Annual Report to the Board can be reconciled to the reported cost of debt above as follows:

	2013	2014
Cost of Debt (Line 14)	7.06%	6.72%
AFUDC	0.18%	0.27%
Cost of Debt - Return 25	7.24%	6.99%

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Rate of Return on Rate Base
($000s)

		Actual		Forecast		
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Regulated Return on Equity	38,042 [1]	39,272	39,769	37,752	35,661
2	Return on Preferred Equity	563	557	552	552	552
3		38,605	39,829	40,321	38,304	36,213
4						
5	Finance Charges					
6	Interest on Long-term Debt	35,123	36,327	35,027	35,439	37,091
7	Other Interest	1,075	626	1,051	757	429
8	Amortization of Bond Issue Expenses	302	254	245	220	213
9	AFUDC	(891)	(1,435)	(974)	(1,071)	(1,089)
10		35,609	35,772	35,349	35,345	36,644
11						
12	Return on Rate Base	74,214	75,601	75,670	73,649	72,857
13						
14	Average Rate Base	915,820	964,930	1,015,999	1,057,566	1,102,441
15						
16	Rate of Return on Rate Base	8.10%	7.83%	7.45%	6.96%	6.61%

[1] The regulated return on equity for 2013 includes a $49,000 (net of income taxes) adjustment for excess earnings. See Return 13, line 2, of the 2013 Annual Report to the Board.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Inputs and Assumptions

Energy Forecasts : Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook, Summer 2015, Economic Forecast, dated July 16, 2015.

Revenue Forecast : The revenue forecast is based on the Customer, Energy and Demand forecast dated August 2015.

Forecast revenues for 2015 through 2017 reflects, (i) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs, (iii) recovery through the RSA of amounts associated with the July 1, 2015 Hydro supply cost rate increase, (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013) and P.U. 18 (2015).

Purchased Power Expense : Purchased power expense reflects Newfoundland & Labrador Hydro's rates approved by the P.U.B. and the Customer, Energy and Demand Forecast dated August 2015.

Purchased power expense for 2013 to 2015 reflects the 3-year amortization of the December 31, 2011 balance in the Weather Normalization reserve of $7.0 million (before-tax).

Purchased Power expense also reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit cost demand costs included in the most recent test year.

Employee Future Benefit Costs : Pension funding is based on the actuarial valuation dated as at December 31, 2014.

Pension expense and OPEBs expense discount rate is 4.00% for 2015 through 2017.

Forecast return on pension assets is assumed to be 5.75% for 2015 through 2017.

Cost recovery deferrals: In Order P.U. 13 (2013), the Board approved a 3-year amortization of (i) $1.0 million in hearing costs related to the 2013/2014 general rate application, (ii) $2.5 million in costs related to the 2012 cost of capital approved by the Board in Order No. P.U. 17 (2012), (iii) $4.7 million in costs related to the 2011 and 2012 deferred costs approved by the Board in Order Nos. P.U. 30 (2010) and P.U. 22 (2011), and (iv) $4.0 million in costs related to a 2013 revenue shortfall amount.

The 2015 to 2017 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.

Depreciation Rates : Depreciation rates are based on the 2010 depreciation study.

Depreciation costs include an $89,000 reserve variance adjustment resulting from the 2010 depreciation study.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Inputs and Assumptions

Operating Costs : Operating forecasts for 2015 and 2016 reflect most recent management estimates. Operating forecasts for 2016 and 2017 reflect projected increases of 3.25% per year for labour, and non labour increases based upon the GDP deflator.

Capital Expenditure : Capital Expenditures for 2015 reflect most recent management estimates.

Capital Expenditures for 2016 and 2017 are based on the 2016 capital budget approved on September 8, 2015.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 1.71% for 2015 and 1.83% for 2016 and 2.55% for 2017.

Long-Term Debt : A $75.0 million long-term debt issue was completed in September 2015. The debt is forecast for 30 years at a coupon rate of 4.446%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

A $75.0 million long-term debt issue is forecast to be completed in November 2016. The debt is forecast for 30 years at a coupon rate of 5.00%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component near 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 29% for 2015 through 2017.

Credit Rating Reports:
Moody's and DBRS

MOODY'S
INVESTORS SERVICE

Credit Opinion: Newfoundland Power Inc.

Global Credit Research - 19 Jan 2015

St. John's, Newfoundland, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating -Dom Curr	Baa1
First Mortgage Bonds -Dom Curr	A2

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Key Indicators

[1]**Newfoundland Power Inc.**

	9/30/2014(L)	12/31/2013	12/31/2012	12/31/2011	12/31/2010
CFO pre-WC + Interest / Interest	**4.2x**	**3.9x**	**3.3x**	**3.2x**	**3.5x**
CFO pre-WC / Debt	**21.7%**	**20.1%**	**15.8%**	**16.3%**	**18.5%**
CFO pre-WC - Dividends / Debt	**17.5%**	**15.8%**	**13.8%**	**6.3%**	**15.3%**
Debt / Capitalization	**49.4%**	**49.7%**	**51.9%**	**51.5%**	**48.0%**

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk regulated electric utility

Supportive regulatory and business environment

NPI is independent of Fortis Inc.

Corporate Profile

Headquartered in St. John's, Newfoundland, Newfoundland Power Inc. (NPI) is a vertically integrated electric utility serving a customer base of over 259,000 accounts, which are 87% residential and 13% commercial. NPI operates under cost of service regulation and is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) under the Public Utilities Act (the Act). NPI purchases the majority of its power from Newfoundland and Labrador Hydro. NPI's installed generating capacity of 139 MW provides about 7% of its power supply. NPI is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), which is primarily a diversified electric and gas utility holding company also based in St. John's.

SUMMARY RATING RATIONALE

NPI's Baa1 issuer rating reflects the company's low business risk as a vertically integrated cost-of-service regulated utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially-owned Newfoundland & Labrador Hydro (Hydro), the cost of which is passed through to ratepayers. Despite NPI's allowed Return on Equity (ROE) of 8.80% for 2013-2015, we continue to view the PUB as one of the more supportive regulators in Canada. Regulatory decisions tend to be reasonably timely and balanced and NPI's 45% deemed equity is among the highest in Canada. In addition, NPI benefits from a number of deferral accounts that are intended to protect it from factors beyond management's control. The rating is consistent with NPI's financial metrics but reflects a cautionary note related to our concern that the utility's future ability to fully recover costs and earn returns may be compromised as the Province of Newfoundland and Labrador undertakes development of the Muskrat Falls hydroelectric project on the lower Churchill river and the related transmission infrastructure. This politically charged project is large relative to the provincial economy and is expected to place considerable upward pressure on future electricity rates. The A2 rating of NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets.

DETAILED RATING CONSIDERATIONS

LOW-RISK BUSINESS MODEL

NPI's rating reflects the company's low business risk as a cost of service-regulated utility. NPI owns and operates a vertically integrated electric utility located on the island portion of the province of Newfoundland and Labrador and dominates that market, which is geographically isolated and effectively protected from potential competition. NPI serves roughly 87% of the province's electricity customers. The market is mature and NPI's electricity sales have tended to grow at a relatively low and predictable rate of 1-2% annually. Historically, growth has not taxed NPI either operationally or financially due to relatively timely recovery of capital and operating costs.

Although NPI is vertically integrated, NPI's own generation assets are regulated and represent only 14% of NPI's net property, plant and equipment. Accordingly, we consider the business risk of NPI to be lower than that of a typical vertically integrated utility, which is often exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation. However, NPI faces uncertainties due to the timing and size of rate increases in association with the Muskrat Falls hydroelectric project.

SUPPORTIVE REGULATORY AND BUSINESS ENVIRONMENT

All of NPI's operations are located in Canada whose well developed regulatory framework and business environments we consider supportive relative to those in other jurisdictions. Furthermore, we consider the PUB's regulation of NPI to be supportive with a track record of reasonably timely and balanced decisions that enable NPI to generate stable cash flow and earn its allowed ROE and are not directly subject to political interference. NPI has access to courts for disputes with the PUB.

The PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis. NPI submits a proposed capital plan for PUB approval annually before the next fiscal year. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any First Mortgage Bonds (FMB) or the incurrence of credit facilities with maturities exceeding one year.

NPI is allowed to file a rate application based on a forward test year and forecast rate base, reducing revenue lag associated with capital projects. NPI's allowed ROE of 8.80% is expected to remain at that level for the period 2013-2015. While it remains relatively low, it is mitigated by one of the highest deemed equity levels in Canada at 45%. NPI's outperformance, as suggested by CFO pre-W/C to debt of over 20% both in 2013 and on an LTM basis, reflected changes in regulated assets and liabilities and pension liability reduction in 2013. However, with the current allowed ROE, deemed equity layer and depreciation rate, we expect NPI to achieve sustainable CFO pre-W/C to debt consistent with our expectations and the current rating. NPI is required to file its next rate case by 1 June 2015 to establish rates for 2016.

Several cost recovery mechanisms reduce NPI's exposure to unexpected costs due to variations in purchased power costs, weather and pension and other post-employment benefit (OPEB) costs. While NPI foregoes some upside potential, the stability and predictability of its cash flows are increased. For example, the Rate Stabilization Account (RSA) facilitates timely recovery of purchased power costs in excess of those forecasted for rate-making purposes. This is particularly important since the marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. The RSA provides for the amortization of the under or over collection over a 12 month period. Other mechanisms include the Weather Normalization Account, Conservation and Demand Management Deferral and the Demand Management Incentive Account (which limits NPI's exposure to variation in purchased power costs due to demand to 1% of demand costs reflected in the test year for rate-making purposes).

NPI IS INDEPENDENT OF FORTIS INC.

While NPI is one of a number of utility operating companies owned by Fortis, we consider NPI, like sister companies FortisAlberta Inc., FortisBC Inc. (FBC: Baa1 stable) and FortisBC Energy Inc. (FEI: A3 stable), to be operationally and financially independent from Fortis. Fortis has consistently demonstrated good management and support of its subsidiaries and we view NPI's access to the executive and strategic support of Fortis to be a credit positive. If required, we expect that Fortis Inc. would provide extraordinary support to NPI, provided that the parent had the economic incentive to do so, and we believe that the parent will continue to have sufficient resources to do so.

Structural Considerations

The A2 rating of NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets. This is consistent with the two notch differential between most senior secured debt ratings and senior unsecured debt ratings of investment-grade regulated utilities operating in North America. The differential is based on our analysis of the history of regulated utility defaults, which indicates that regulated utilities have experienced lower loss given default rates (higher recovery rates) than non-financial, non-utility corporate issuers.

Liquidity Profile

NPI's liquidity arrangements are considered adequate in the context of its relatively stable cash flow and funding requirements.

In 2015, NPI plans to spend about $94 million on capital expenditures and pay dividends in amounts commensurate with maintaining the 45% deemed equity layer. Additionally, NPI requires $5.5 million for sinking fund installments in 2015 and it does not have any bond maturities until April 2016. With estimated cash flow from operations in the range of $110-120 million, we expect that any free cash flow shortfall is funded through NPI's bank credit facilities and adjustments to dividends paid.

The company's core liquidity facility is a $100 million syndicated committed revolving credit facility that matures in August 2019. While the credit agreement contains a covenant that NPI maintain its debt to capitalization ratio at or below 65%, it does not include a material adverse change (MAC) clause or representation and warranty declaration prior to drawdown. Unutilized capacity under this facility was $67 million at 30 September 2014.

Rating Outlook

The rating outlook is stable based on the PUB's regulation of NPI which we consider credit supportive and expect to remain so, as well as our expectation that, with relatively stable cash flow generation and capital structure NPI will continue to generate sustained CFO pre-WC to debt in the range of 14% to 17%.

What Could Change the Rating - Up

NPI's rating would likely be upgraded if there was a sustainable improvement in financial metrics, such as CFO pre-WC to debt above 17%. An upgrade of NPI's rating is unlikely without further clarity on the timing and size of increase in electricity rates in relation to the Muskrat Falls hydroelectric project.

What Could Change the Rating - Down

We consider a downward revision in NPI's rating to be unlikely in the near term. However, NPI's rating would likely be downgraded if we perceived a meaningful reduction in the level of regulatory support combined with a sustained deterioration in NPI's financial metrics such as CFO pre-WC to debt in the low teens.

Rating Factors

Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 9/30/2014**		[3]**Moody's 12-18 Month Forward ViewAs of 1/16/2015**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.5x	Baa	3.2x - 3.8x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	17.6%	Baa	15% - 18%	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	12.3%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	49.9%	Baa	48% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching			0	0
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned				Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 9/30/2014(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares - cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating Update

On August 13, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating and First Mortgage Bonds rating of Newfoundland Power Inc. (Newfoundland Power or the Company) at "A," and the Preferred Shares – cumulative, redeemable rating at Pfd-2, all with Stable trends. The confirmations reflect the stable nature of the Company's regulated electricity distribution business and its solid financial risk profile.

Newfoundland Power's business risk profile continues to be supported by the reasonable regulatory regime in Newfoundland and Labrador. The Company, which is regulated by the Board of Commissioners of Public Utilities (PUB), operates under a cost-of-service (COS) framework, which allows Newfoundland Power to recover all prudently spent operating expenses and earn a reasonable return. The Company currently has an allowed return on equity (ROE) of 8.80% and regulated capital structure of 45% common equity, which is comparable to its peers across Canada. Newfoundland Power also benefits from having a Rate Stabilization Account (RSA) and a Weather Normalization Account (WNA), which help reduce volatility in its earnings. These accounts limit the Company's exposure to power price risk as the RSA passes through to customers changes in the cost and quantity of fuel burned by the Company's main power supplier, Newfoundland and Labrador Hydro (NLH; rated "A" with a Stable trend by DBRS), while the WNA stabilizes earnings during extreme weather conditions.

Newfoundland Power filed an application with the PUB in April 2015 to approve a return on rate base for 2016 of 7.38%, a 2016 cost-recovery deferral of approximately $4.0 million and to defer the Company's next general rate application (GRA) filing to on or before June 1, 2016. The PUB denied the application and confirmed that the Company will be required to file its next GRA by October 16, 2015, to establish customer electricity rates for 2016. DBRS does not expect any material changes from the GRA but notes that a lower approved ROE is a possibility due to the current low interest rate environment. A modest decrease in the allowed ROE is not expected to have a material impact on the Company's operations.

The Company's financial risk profile remains solid with all key credit metrics in line with the current rating category. Newfoundland Power is currently experiencing elevated capital expenditures (capex; $117 million of gross capex in 2014) in order to maintain its distribution infrastructure and to connect new customers to the system. The Company, which has forecast average capex of $108 million for the next five years, has funded its capex and dividends through internally generated cash flow while modest free cash flow deficits have been funded with debt. DBRS expects the Company to continue to manage these deficits prudently through dividend management (quarterly common share dividends decreased to $0.23 per share for 2015, from $0.56 per share in 2014) and debt financing in order to maintain its leverage in line with the regulatory capital structure.

Financial Information

	12 mos. to June 30	For the year ended December 31				
(CA$ millions where applicable)	2015	2014	2013	2012	2011	2010
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
EBIT gross interest coverage (times)	3.20	3.06	2.95	2.74	2.88	2.76
(CFO+interest)/(Interest+sinking fund payment)	3.12	3.18	3.16	2.90	3.02	3.01

Issuer Description

Newfoundland Power is a regulated utility that primarily distributes, but also generates and transmits, electricity to approximately 260,000 customers throughout the island portion of the Province of Newfoundland and Labrador (the Province). Newfoundland Power is a wholly owned subsidiary of Fortis Inc. (rated A (low) with a Stable trend by DBRS).

Rating Considerations

Strengths

1. Stable and supportive regulatory environment

Newfoundland Power operates in a stable and supportive regulatory environment that is based on COS regulation. The PUB allows for the pass-through of purchased power costs and an RSA is in place to absorb fluctuations in purchased power costs relating primarily to the cost of fuel oil used by NLH to generate electricity. Furthermore, the Company also has a WNA to stabilize earnings during extreme weather conditions.

2. Solid financial profile

Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flows. During the last 12 months ended June 30, 2015 (LTM 2015), Newfoundland Power's total debt in capital structure remained low at 55.4%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 16.2% and 3.20x, respectively.

3. Stable customer base

Newfoundland Power has a stable customer base, with power sales consisting solely of those to residential and commercial customers.

Challenges

1. Reliance on one major power supplier

Newfoundland Power relies heavily on NLH for its power supply, sourcing approximately 93% of its power requirements from this provider. The cost of power purchased from NLH is largely influenced by the market price of bunker C fuel, which is passed through to Newfoundland Power's customers through the RSA. Although the Company's rate increases have been reasonable, higher rates, driven by the high cost of oil in recent years and NLH's high capex program over the next few years, could make it more difficult for the Company to receive approval for future rate increases. However, NLH is looking to reduce its exposure to highly expensive and volatile oil. The Muskrat Falls project could potentially replace the oil-fired power generated at the Holyrood Thermal Generating Station with cleaner hydro-generated power.

2. Managing forecast risk

The Company's ability to accurately and consistently forecast electricity demand going forward, with respect to forecasting sales and managing the demand management incentive account (DMIA), is a challenge. However, through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs. In the deliberation of the final value to be placed in the DMIA, the PUB considers the merits of the Company's conservation and demand management activities.

3. Limited population growth

Electricity consumption growth in Newfoundland and Labrador is largely driven by growth in the customer base, which is dependent on population growth. Over the years, population growth in the Province has been relatively flat, as it is limited by the Province's geographic isolation.

Earnings and Outlook

(CA$ millions where applicable)	12 mos. to June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net revenues	228	227	214	203	204	197
EBITDA	170	167	158	146	147	143
EBIT	115	113	107	98	104	100
Gross interest expense	36	37	36	36	36	36
Earning before taxes	50	49	46	45	50	51
Net income before non-recurring items	39	38	36	35	32	36
Reported net income	39	38	50	37	32	36
Actual return on equity	8.7%	8.6%	8.6%	8.9%	8.2%	8.9%

2014 Summary

- Earnings increased in 2014 largely due to higher electricity sales and the rebasing of customer rates effective July 1, 2013, reflecting growth in the rate base.
- This was partially offset by (1) higher operating costs related to the restoration and customer service efforts following the loss of generation supply from NLH and power interruptions in January 2014 and (2) higher depreciation due to the higher asset base.
- Reported net income in 2013 was positively impacted by $12.8 million of income tax recovery recorded in the year and a $1.2 million gain on the sale of land.

2015 Summary/Outlook

- Earnings in LTM 2015 increased modestly due to (1) lower operating costs compared to Q1 2014, which was impacted by the above-mentioned power interruptions and (2) lower interest expenses following the maturity of $29 million of first mortgage sinking fund bonds in August 2014.
- DBRS expects Newfoundland Power's earnings to be slightly higher in 2015, compared to 2014, reflecting the increase in the Company's rate base.

Financial Profile

(CA$ millions where applicable)	12 mos. to June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net income before non-recurring items	39	38	36	35	32	36
Depreciation & amortization	56	54	52	48	43	44
Deferred income taxes and other	(2)	6	7	1	13	9
Cash flow from operations	**93**	**98**	**95**	**84**	**89**	**88**
Dividends paid	(17)	(24)	(23)	(11)	(51)	(16)
Capital expenditures	(123)	(113)	(89)	(82)	(79)	(75)
Free cash flow (bef. working cap. changes)	**(47)**	**(39)**	**(18)**	**(9)**	**(41)**	**(3)**
Changes in non-cash work. cap. items	12	5	(4)	(8)	(7)	6
Net free cash flow	**(35)**	**(34)**	**(22)**	**(17)**	**(48)**	**3**
Acquisitions & investments	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	(1)	45	0
Net equity change	(0)	(0)	(0)	0	(0)	0
Net debt change	35	34	22	17	(0)	(4)
Other	(0)	(0)	(0)	0	(0)	(0)
Change in cash	**0**	**(0)**	**0**	**(0)**	**(4)**	**(1)**
Total debt	575	552	518	496	478	475
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
EBIT gross interest coverage (times)	3.20	3.06	2.95	2.74	2.88	2.76
Dividend payout ratio	43.1%	62.6%	64.8%	32.6%	156.2%	45.7%

Financial Profile (CONTINUED)

2014 Summary

- Newfoundland Power's financial profile remained solid with key credit metrics in line with the current rating category.
- The Company's cash flow from operations increased in 2014 largely due to the higher net income before non-recurring items for the year.
- Newfoundland Power had gross capex of approximately $117 million in 2014, with around $59 million spent on maintaining the distribution network and to connect new customers to the system. The higher capex for the year also reflected $14 million of supplemental capex for the replacement of the submarine cable system that supplies electricity to Bell Island.
- Newfoundland Power utilizes its annual dividend to maintain a long-term capital structure of 55% debt and 45% equity, as approved by the PUB for rate-setting purposes. In 2014, Newfoundland Power paid approximately $24 million in dividends to maintain its leverage in line with the approved capital structure.
- The Company incurred a free cash flow deficit of approximately $39 million in 2014, which was funded with debt.

2015 Summary/Outlook

- The Company's key credit metrics remained stable in LTM 2015. Although the cash flow-to-debt ratio decreased due to lower cash flow from operations and a higher debt load, it remained commensurate with the current rating category. The decrease in cash flow from operations was due to the timing of payments to NLH for power purchases.
- The PUB approved Newfoundland Power's 2015 capital plan of $94 million in October 2014. The Company has spent approximately $52 million as of June 30, 2015.
- The Company decreased its quarterly common share dividends to $0.23 per share, from $0.56 per share in 2014, in order to maintain its leverage in line with the regulatory capital structure.
- In April 2015, the PUB approved Newfoundland Power's application to issue up to $100 million of Series AO First Mortgage Bonds by December 31, 2015. The issuance is expected to be used to repay short-term borrowings ($91.5 million outstanding as of June 30, 2015).
- DBRS expects the Company to continue to maintain its approved capital structure through dividend management and debt financing.

Long-term Debt Maturities and Liquidity

- Newfoundland Power has a $100 million committed revolving unsecured credit facility expiring in August 2019 ($91.5 million outstanding as at June 30, 2015) and a $20 million uncommitted demand facility ($0 outstanding as at June 30, 2015).
- The credit facilities contain a covenant that states that the Company shall not declare or pay any dividends or make any other restricted payments if the debt-to-capitalization ratio exceeds 65%.

(CA$ millions — as at June 30, 2015)	2015-2016	2016-2017	2018-2019	Thereafter	Total
First mortgage sinking fund bonds	35.9	10.2	10.2	427.3	483.6
Related party loan	0.0	0.0	0.0	0.0	0.0
Credit facilities (unsecured)	91.5	0.0	0.0	0.0	91.5
Demand facility (uncommitted)	0.0	0.0	0.0	0.0	0.0
Total	**127.4**	**10.2**	**10.2**	**427.3**	**575.1**

Note: Gross debt; debt issue costs not subtracted from total debt.

- The debt repayment schedule is very modest in the near term. The most notable maturity was in 2014, which included the Series AD (approximately $29.0 million), which was repaid by the Company on August 1, 2014.

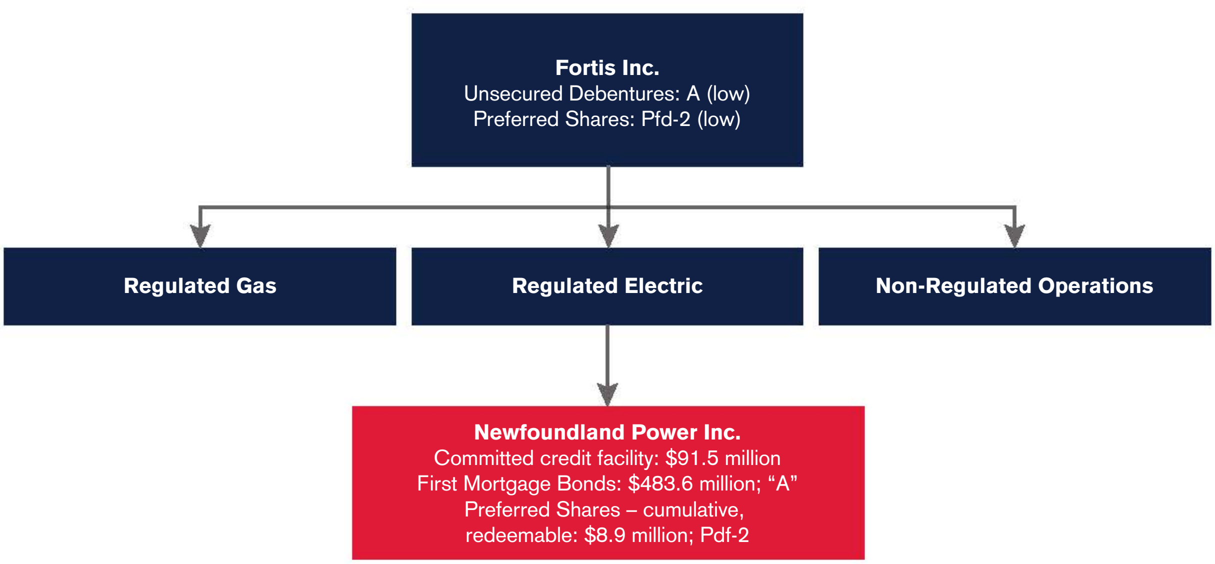
Long-term Debt Maturities and Liquidity (CONTINUED)

Securities Outstanding (CA$ millions)
First mortgage sinking fund bonds:

(CA$ millions)		June 30, 2015
$40 million Series AE, due 2016	10.900%	30.8
$40 million Series AF, due 2022	10.125%	31.2
$40 million Series AG, due 2020	9.000%	32.0
$40 million Series AH, due 2026	8.900%	32.8
$50 million Series AI, due 2028	6.800%	42.0
$75 million Series AJ, due 2032	7.520%	66.0
$60 million Series AK, due 2035	5.441%	54.0
$70 million Series AL, due 2037	5.901%	64.4
$65 million Series AM, due 2039	6.606%	61.1
$70 million Series AN, due 2043	4.805%	69.3
		483.6
	Related party loan	0.0
	Credit & demand facilities	91.5
		575.1
	Less: current portion	127.4
		447.7

- The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.
- The Company must meet an Earnings Test, whereby the net earnings are at least two times the annual interest charges on all bonds outstanding after any proposed additional bond issue. Net earnings are considered in a period of any 12 consecutive months terminating within 24 months preceding the delivery of such additional bonds.
- Second, the Company must meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.
- Given the availability of funds under the credit facilities and stable cash flow from operations, the Company's liquidity remains adequate to fund both working capital requirements and cash flow deficits.

Organizational Structure



As at June 30, 2015.

Regulation

Regulatory Overview

- Newfoundland Power is regulated by the PUB, which is responsible for setting electricity rates, approving capex and deciding on the appropriate capital structure and ROE for rate-setting purposes.
- Rates are set based on a cost-of-service methodology.
- On April 17, 2013, the PUB issued the Order on Newfoundland Power's 2013/2014 GRA, which established the Company's allowed ROE at 8.80% and common equity at 45% for the 2013 to 2015 rate years. This is consistent with the cost of capital allowed in 2012. DBRS views the capital structure as favourable and the ROE as reasonable when compared to other Canadian jurisdictions.
- The operation of the Automatic Adjustment Formula has been suspended until the next GRA.
- On July 1, 2014, customer electricity rates increased by approximately 2.0% on average due to the operation of the annual Rate Stabilization Plan.
- The Company's 2014 capital plan totalling $108.8 million was approved by the PUB and included $14.5 million associated with replacing the submarine cable system that supplies electricity to Bell Island.
- The PUB approved Newfoundland Power's 2015 capital plan of $94.2 million on October 9, 2014. The PUB additionally fixed the Company's average rate base for the year ending December 31, 2013, at $915.8 million.
- On July 1, 2015, customer electricity rates decreased by approximately 5.25% on average due to (1) a 10.0% rate decrease associated with the annual operation of the Rate Stabilization Plan, and (2) a 4.75% interim rate increase in the wholesale electricity rate charged by NLH to the Company.
- As a result of the elimination of the residential energy rebate by the Province effective July 1, 2015, residential customers will see an average rate increase of approximately 3.1%.
- Newfoundland Power filed an application with the PUB on April 15, 2015, to approve a return on rate base for 2016 of 7.38% with a range of 7.20% to 7.56%, a 2016 cost-recovery deferral of approximately $4.0 million and to defer the Company's next GRA filing to on or before June 1, 2016. The PUB denied the application on July 15, 2015, and confirmed that the Company will be required to file its next GRA by October 16, 2015, to establish customer electricity rates for 2016.

Regulator-Approved Accounts

- Deferral accounts are used to smooth the impact of realized expenses and events differing from forecast.
- ***Weather Normalization Reserve (WNR):*** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate the variance between normal weather conditions, based on long-term averages, and actual realized weather conditions.
- ***Rate Stabilization Account (RSA):*** The RSA allows Newfoundland Power to pass through costs related to changes in the price and quantity of fuel charged by NLH to the end consumer. On July 1 of each year, customer rates are recalculated in order to amortize, over the subsequent 12 months, the balance in the RSA as of March 31 of the current year. In the absence of rate regulation, these transactions would be accounted for in a similar manner; however, the amount and timing of the recovery would not be subject to PUB approval. To the extent that actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. Effective January 1, 2008, the PUB ordered that variations in purchased power expense caused by differences between the actual unit cost of energy and the cost reflected in customer rates be recovered from (refunded to) customers through the RSA.
- ***Demand Management Incentive Account (DMIA):*** Through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheet. The final balance of regulatory assets and liabilities is determined by the PUB, which takes into consideration the merits of the Company's conservation efforts and demand management activities.
- ***Pension Expense Variance Deferral Account (PEVDA):*** The PEVDA is utilized when differences exist between the defined benefit pension expense calculated in accordance with designated accounting standards and the pension expense approved by the PUB for rate-setting purposes.
- ***Other Post-Employment Benefits:*** The other post-employment benefits cost deferral account (OPEB) is utilized when differences exist between the OPEB expense calculated in accordance with designated accounting standards and the OPEB expense approved by the PUB for rate-setting purposes.
- ***Excess Earnings Account (EEA):*** Any earnings which exceed the upper limit of the allowed range of return on rate base set by the PUB are credited to the Company's EEA. Amounts credited to the EEA are subject to further order of the PUB.

Newfoundland Power Inc.

(CA$ millions)	June 30	Dec. 31			June 30	Dec. 31	
Assets	**2015**	**2014**	**2013**	**Liabilities and Equity**	**2015**	**2014**	**2013**
Cash & equivalents	0	0	0	S.T. borrowings	0	4	0
Accounts receivable	74	82	90	Accounts payable	50	80	82
Regulatory assets	26	30	32	Current portion L.T.D.	127	70	34
Prepaid expenses & other	5	6	4	Other current liab.	18	18	18
Total Current Assets	**106**	**118**	**126**	**Total Current Liab.**	**195**	**172**	**135**
Net fixed assets	1,005	984	915	Long-term debt	448	478	484
Future income tax assets	182	177	171	Provisions	229	233	230
Intangibles	16	16	15	Deferred income taxes	126	120	116
Regulatory assets	149	151	169	Other L.T. liab.	1	1	6
Investments & others	4	4	4	Preferred shares	9	9	9
				Common equity	454	437	422
Total Assets	**1,462**	**1,450**	**1,401**	**Total Liab. & SE**	**1,462**	**1,450**	**1,401**

	12 mos. to June 30	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
Current ratio	0.54	0.69	0.94	0.77	1.10	1.04
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
(Cash flow-dividends)/Capex (times)	0.62	0.66	0.80	0.88	0.48	0.96
Dividend payout ratio	43.1%	62.6%	64.8%	32.6%	156.2%	45.7%
Coverage Ratios (times)						
EBIT gross interest coverage	3.20	3.06	2.95	2.74	2.88	2.76
EBITDA gross interest coverage	4.75	4.52	4.36	4.05	4.07	3.95
Fixed-charges coverage	3.14	3.00	2.88	2.68	2.82	2.69
Profitability Ratios						
EBITDA margin	74.5%	73.7%	73.9%	72.0%	72.2%	72.7%
EBIT margin	50.2%	49.9%	49.9%	48.6%	51.2%	50.6%
Profit margin	17.1%	16.7%	16.8%	17.1%	15.9%	18.1%
Return on equity	8.7%	8.6%	8.6%	8.9%	8.2%	8.9%
Return on capital	6.3%	6.5%	6.6%	6.8%	6.6%	6.8%

Operating Statistics

	For the year ended December 31				
Electricity sales — breakdown (GWh)	**2014**	**2013**	**2012**	**2011**	**2010**
Residential	3,613	3,531	3,441	3,407	3,311
General service	2,286	2,232	2,211	2,146	2,108
Total sales	**5,899**	**5,763**	**5,652**	**5,553**	**5,419**
Growth in volume throughputs	2.4%	2.0%	1.8%	2.5%	2.3%
Customers					
Residential	224,824	221,995	218,290	214,515	211,091
Commercial	34,055	33,623	33,241	32,648	32,335
Total	**258,879**	**255,618**	**251,531**	**247,163**	**243,426**
Energy generated and purchased (GWh)					
Energy generated	430	429	432	422	425
Energy purchased	5,817	5,678	5,544	5,456	5,308
Energy generated + purchased	**6,247**	**6,107**	**5,976**	**5,878**	**5,733**
Less: transmission losses + internal use	348	344	324	325	314
Total Sales	**5,899**	**5,763**	**5,652**	**5,553**	**5,419**
System losses and internal use	5.9%	6.0%	5.7%	5.9%	5.8%
Installed generation capacity (MW)					
Hydroelectric	97	97	97	97	97
Gas turbine	37	37	37	37	37
Diesel	5	5	6	7	7
Total	**139**	**139**	**140**	**140**	**140**
Native peak demand (MW)	1,343	1,281	1,241	1,166	1,206
Rate base ($ millions)	965	916	883	876	875
Growth in rate base	5%	4%	1%	0%	3%

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A	A	A	A	NR	NR
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, August 13, 2015.

Previous Report

- Newfoundland Power Inc., August 13, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Income
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Revenue from rates	661,775	669,685	665,246	682,578
2	Transfers from (to) the RSA	6,481	6,488	3,885	2,828
3		668,256	676,173	669,131	685,406
4					
5	Purchased power expense	449,006	448,197	450,829	447,927
6	Demand management incentive account adjustments	-	-	-	-
7		449,006	448,197	450,829	447,927
8					
9	Contribution	219,250	227,976	218,302	237,479
10					
11	Other revenue[1]	4,842	4,805	4,770	4,832
12					
13	Other expenses:				
14	Operating expenses[2]	58,123	58,523	59,770	60,170
15	Employee future benefit costs	22,176	22,176	17,892	17,892
16	Deferred cost recoveries and amortizations	-	(3,276)	-	1,638
17	Depreciation	54,634	55,535	57,640	58,573
18	Finance charges	35,369	35,429	36,668	36,773
19		170,302	168,387	171,970	175,046
20					
21	Income Before Income Taxes	53,790	64,394	51,102	67,265
22	Income taxes[2]	15,486	18,585	14,889	19,598
23					
24	Net Income	38,304	45,809	36,213	47,667
25	Preferred Dividends	552	552	552	552
26					
27	Earnings Applicable to Common Shares[2]	37,752	45,257	35,661	47,115
28					
29	**Rate of Return and Credit Metrics**				
30	Rate of Return on Rate Base (percentage)	6.96%	7.66%	6.61%	7.64%
31	Regulated Return on Book Equity (percentage)	7.96%	9.50%	7.22%	9.50%
32	Interest Coverage (times)	2.2	2.5	2.1	2.5
33	CFO Pre-W/C + Interest / Interest (times)	3.9	4.1	3.8	4.2
34	CFO Pre-W/C / Debt (percentage)	17.5%	18.8%	16.9%	19.3%

[1] Other revenue for proposed excludes interest on the RSA.

[2] Shown are after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Income
($000s)

		2016		2017	
		Existing	Proposed	Existing	Proposed
1	Balance - Beginning	395,088	395,088	412,393	416,907
2	Net income for the period	36,181	43,689	33,922	45,375
3	Allocation of Part VI.1 Tax	252	252	252	252
4		431,521	439,029	446,567	462,534
5					
6	Dividends				
7	Preference shares	552	552	552	552
8	Common shares	18,576	21,570	11,559	27,762
9		19,128	22,122	12,111	28,314
10	Balance - End of Period	412,393	416,907	434,456	434,220

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Balance Sheets
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Assets**				
2	**Current assets**				
3	Accounts receivable	$ 93,863	$ 96,108	$ 93,712	$ 97,838
4	Materials and supplies	1,343	1,343	1,371	1,371
5	Prepaid expenses	1,343	1,343	1,371	1,371
6	Regulatory assets	18,256	20,227	15,132	16,281
7		114,805	119,021	111,586	116,861
8					
9	**Property, plant and equipment**	1,087,983	1,087,913	1,144,158	1,144,028
10	**Intangible assets**	22,777	22,777	24,465	24,465
11	**Regulatory assets**	299,326	301,152	292,733	290,599
12	**Defined benefit pension plans**	14,948	14,948	20,115	20,115
13	**Other assets**	4,186	4,186	3,973	3,973
14		$ 1,544,025	$ 1,549,997	$ 1,597,030	$ 1,600,041
15					
16					
17	**Liabilities and Shareholders' Equity**				
18	Current Liabilities				
19	Accounts payable and accrued charges	87,045	87,532	87,624	87,248
20	Interest payable	6,738	6,738	6,460	6,460
21	Defined benefit pension plans	233	233	227	227
22	Other post employment benefits	3,377	3,377	3,667	3,667
23	Current installments of long-term debt	6,600	6,600	6,600	6,600
24	Deferred income taxes	4,984	4,984	4,984	4,984
25		108,977	109,464	109,562	109,186
26					
27	**Regulatory liabilities**	146,058	147,012	151,809	153,836
29	**Other post employment benefits**	86,989	86,989	88,984	88,984
30	**Other liabilities**	700	700	700	700
31	**Deferred income taxes**	124,474	124,998	125,743	125,343
32	**Long-term debt**	585,165	584,658	606,507	608,503
33					
34	**Shareholders' Equity**				
35	**Common shares**	70,321	70,321	70,321	70,321
36	**Preference shares**	8,948	8,948	8,948	8,948
37	**Retained earnings**	412,393	416,907	434,456	434,220
38		491,662	496,176	513,725	513,489
39		$ 1,544,025	$ 1,549,997	$ 1,597,030	$ 1,600,041

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Cash Flows
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Cash From (Used In) Operating Activities**				
2	Net Earnings	$ 36,181	$ 43,689	$ 33,922	$ 45,375
3					
4	**Items not affecting cash:**				
5	Amortization of property, plant and equipment	56,760	57,852	59,623	60,759
6	Amortization of intangible assets and other	3,187	3,187	3,562	3,562
7	Change in long-term regulatory assets and liabilities	1,953	60	3,722	7,681
8	Deferred income taxes	(669)	(145)	1,269	345
9	Employee future benefits	7,615	7,615	2,627	2,627
10	Other	(230)	(230)	(238)	(238)
11		104,797	112,028	104,487	120,111
12					
13	Change in non-cash working capital	1,097	(2,875)	879	(1,037)
14		105,894	109,153	105,366	119,074
15					
16	**Investing Activities**				
17	Capital expenditures	(109,920)	(109,920)	(113,052)	(113,054)
18	Intangible asset expenditures	(6,145)	(6,145)	(5,037)	(5,037)
19	Contributions from customers and security deposits	3,500	3,500	3,500	3,500
20		(112,565)	(112,565)	(114,589)	(114,591)
21					
22	**Financing Activities**				
23	Net proceeds (repayment) of committed credit facility	(12,551)	(12,817)	27,934	30,431
24	Proceeds from long-term debt	75,000	75,000	-	-
25	Repayment of long-term debt	(36,250)	(36,250)	(6,600)	(6,600)
26	Payment of debt financing costs	(400)	(400)	-	-
27	Dividends				
28	Preference Shares	(552)	(552)	(552)	(552)
29	Common Shares	(18,576)	(21,569)	(11,559)	(27,762)
30		6,671	3,412	9,223	(4,483)
31					
32	**Change in Cash**	-	-	-	-
33	**Cash (Bank Indebtedness), Beginning of Year**	-	-	-	-
34	**Cash (Bank Indebtedness), End of Year**	$ -	$ -	$ -	$ -

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Average Rate Base[1]
($000s)

		2016		2017	
		Existing	Proposed	Existing	Proposed
1	Plant Investment	987,712	987,262	1,043,286	1,041,919
2					
3	Additions to Rate Base				
4	Defined Benefit Pension Costs	95,025	95,025	89,552	89,552
5	Credit Facility Costs	48	28	32	-
6	Cost Recovery Deferral - Seasonal/TOD Rates	55	35	42	-
7	Cost Recovery Deferral - Hearing Costs	-	400	-	600
8	Cost Recovery Deferral - 2016 Revenue Shortfall	-	1,163	-	1,745
9	Cost Recovery Deferral - Conservation	10,014	10,014	13,227	13,227
10	Customer Finance Programs	1,136	1,136	1,136	1,136
11		106,278	107,801	103,989	106,260
12					
13	Deductions from Rate Base				
14	Weather Normalization Reserve	(518)	(518)	-	-
15	Other Post Employee Benefits	42,656	42,656	48,947	48,947
16	Customer Security Deposits	700	700	700	700
17	Accrued Pension Obligation	5,149	5,149	5,513	5,513
18	Future Income Taxes	1,999	1,880	3,400	3,039
19	Excess Earnings	48	24	48	-
20		50,034	49,891	58,608	58,199
21					
22	Average Rate Base Before Allowances	1,043,956	1,045,172	1,088,667	1,089,980
23					
24	Cash Working Capital Allowance	7,096	8,484	7,124	8,270
25					
26	Materials and Supplies Allowance	6,514	6,675	6,650	6,814
27					
28	Average Rate Base At Year End	1,057,566	1,060,331	1,102,441	1,105,064

[1] All amounts shown are averages.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Weighted Average Cost of Capital
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Average Capitalization**				
2	Debt	575,703	575,328	599,493	600,237
3	Preference Shares	8,948	8,948	8,948	8,948
4	Common Equity	474,060	476,315	493,739	495,885
5		1,058,711	1,060,591	1,102,180	1,105,070
6					
7	**Average Capital Structure**				
8	Debt	54.38%	54.25%	54.39%	54.32%
9	Preference Shares	0.84%	0.84%	0.81%	0.81%
10	Common Equity	44.78%	44.91%	44.80%	44.87%
11		100.00%	100.00%	100.00%	100.00%
12					
13					
14	**Cost of Capital**				
15	Debt	6.14%	6.15%	6.11%	6.12%
16	Preference Shares	6.17%	6.17%	6.17%	6.17%
17	Common Equity	7.96%	9.50%	7.22%	9.50%
18					
19					
20	**Weighted Average Cost of Capital**				
21	Debt	3.34%	3.34%	3.32%	3.33%
22	Preference Shares	0.05%	0.05%	0.05%	0.05%
23	Common Equity	3.57%	4.27%	3.24%	4.26%
24		6.96%	7.66%	6.61%	7.64%

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Rate of Return on Rate Base
($000s)

		2016		2017	
		Existing	Proposed	Existing	Proposed
1	Regulated Return on Equity	37,752	45,257	35,661	47,115
2	Return on Preferred Equity	552	552	552	552
3		38,304	45,809	36,213	47,667
4					
5	Finance Charges				
6	Interest on Long-term Debt	35,439	35,439	37,091	37,091
7	Other Interest	757	818	429	534
8	Amortization of Bond Issue Expenses	220	219	213	213
9	AFUDC	(1,071)	(1,071)	(1,089)	(1,089)
10		35,345	35,405	36,644	36,749
11					
12	Return on Rate Base	73,649	81,214	72,857	84,416
13					
14	Average Rate Base	1,057,566	1,060,331	1,102,441	1,105,064
15					
16	Rate of Return on Rate Base	6.96%	7.66%	6.61%	7.64%

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Inputs and Assumptions

Energy Forecasts :	Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook,Summer 2015, Economic Forecast, dated July 16, 2015.
Revenue Forecast :	The revenue forecast is based on the Customer, Energy and Demand forecast dated August, 2015.
	Forecast revenues for 2016 through 2017 reflects, (i) recovery through the RSA for January to July 2016 of amounts associated with the Energy Supply Cost Variance Adjustment Clause (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs, (iii) recovery through the RSA of amounts associated with the July 1, 2015 Hydro supply cost rate increase (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013) and P.U. 18 (2015).
Purchased Power Expense :	Purchased Power expense reflects Newfoundland & Labrador Hydro's rates approved by the P.U.B. and the Customer, Energy and Demand Forecast dated August 2015.
	Purchased Power Expense for the Existing forecasts reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007).
	Variances in demand costs under the Proposed forecasts are reflected in the 2016/2017 revenue requirements.
Employee Future Benefit Costs :	Pension funding is based on the actuarial valuation dated as at December 31, 2014.
	Pension expense and OPEBs expense discount rate is 4.00% for 2015 through 2017.
	Forecast return on pension assets is assumed to be 5.75% for 2015 through 2017.
Cost Recovery Deferrals:	The 2016 and 2017 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.
	The 2016 and 2017 forecasts also include the deferred recovery over a 30 month period of $4.1 million due to a July 1, 2016 rate implementation date.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Inputs and Assumptions

Depreciation Rates : Depreciation costs for 2016 and 2017 include an $626,000 reserve variance adjustment resulting from the 2014 depreciation study.

Operating Costs : Operating forecasts for 2015 reflect most recent management estimates. Operating forecasts for 2016 and 2017 primarily reflect projected increases of 3.25% per year for labour, and non labour increases based upon the GDP deflator.

The 2016 and 2017 forecasts include the deferred recovery over a 3-year period of $1.2 million in external costs related to the 2016 general rate application.

Capital Expenditure : Capital Expenditures for 2016 and 2017 are based on the 2016 capital budget approved on September 8, 2015.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 1.83% for 2016 and 2.55% for 2017.

Long-Term Debt : A $75.0 million long-term debt issue was completed in September 2015. The debt is forecast for 30 years at a coupon rate of 4.446%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

A $75.0 million long-term debt issue is forecast to be completed in November 2016. The debt is forecast for 30 years at a coupon rate of 5.00%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component of 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 29% for 2016 and 2017.

Newfoundland Power Inc.

Forecast Average Rate Base[1]
2016 &2017
($000s)

		2016P	2017P
1	Plant Investment	987,262	1,041,919
2			
3	Additions to Rate Base		
4	Defined Benefit Pension Costs	95,025	89,552
5	Credit Facility Costs	28	-
6	Cost Recovery Deferral - Seasonal/TOD Rates	35	-
7	Cost Recovery Deferral - Hearing Costs	400	600
8	Cost Recovery Deferral - 2016 Revenue Shortfall	1,163	1,745
9	Cost Recovery Deferral - Conservation	10,014	13,227
10	Customer Finance Programs	1,136	1,136
11		107,801	106,260
12			
13	Deductions from Rate Base		
14	Weather Normalization Reserve	(518)	-
15	Other Post Employee Benefits	42,656	48,947
16	Customer Security Deposits	700	700
17	Accrued Pension Obligation	5,149	5,513
18	Future Income Taxes	1,880	3,039
19	Excess Earnings	24	-
20		49,891	58,199
21			
22	Average Rate Base Before Allowances	1,045,172	1,089,980
23			
24	Cash Working Capital Allowance	8,484	8,270
25			
26	Materials and Supplies Allowance	6,675	6,814
27			
28	Average Rate Base At Year End	1,060,331	1,105,064

[1] Based upon proposed rates. All amounts shown are averages.

Newfoundland Power Inc.

2016 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	449,006	(809)	448,197
3	Operating Costs	58,123	400	58,523
4	Employee Future Benefit Costs	22,176	-	22,176
5	Amortization of Deferred Cost Recoveries	-	(3,276)	(3,276)
6	Depreciation	54,634	901	55,535
7	Income Taxes	15,486	3,099	18,585
8		599,425	315	599,740
9				
10	**Return on Rate Base**	73,649	7,565	81,214
11				
12	**2016 Revenue Requirement**	673,074	7,880	680,954
13				
14	**Deductions**			
15	Other Revenue[2]	(4,842)	37	(4,805)
16	Interest on Security Deposits	24	-	24
17	2013 Excess Earnings[3]	-	(68)	(68)
18	Energy Supply Cost Variance Adjustments	(5,227)	701	(4,526)
19	Other	(1,254)	(640)	(1,894)
20		(11,299)	30	(11,269)
21				
22	**2016 Revenue Requirement from Rates[4]**	661,775	7,910	669,685

[1] See *Section 5.3 2016 and 2017 Revenue Requirements* for a summary of the Company's 2016 Revenue Requirements proposals.

[2] Excludes equity component of capitalized interest and interest on the RSA.

[3] 2013 Excess Earnings as shown in Return 13 of the 2013 Annual Report to the Board.

[4] Existing revenue requirement for 2016 excludes price elasticity impacts related to revenue of $805,000. The required revenue increase of $8,715,000 in 2016 (see Exhibit 9, page 1 of 2, line 1, column E) is comprised of $7,910,000 and price elasticity impacts related to revenue of $805,000 (see Exhibit 9, page 1 of 2, line 1, column D).

Newfoundland Power Inc.

2017 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	450,829	(2,902)	447,927
3	Operating Costs	59,770	400	60,170
4	Employee Future Benefit Costs	17,892	-	17,892
5	Amortization of Deferred Cost Recoveries	-	1,638	1,638
6	Depreciation	57,640	933	58,573
7	Income Taxes	14,889	4,709	19,598
8		601,020	4,778	605,798
9				
10	**Return on Rate Base**	72,857	11,559	84,416
11				
12	**2017 Revenue Requirement**	673,877	16,337	690,214
13				
14	**Deductions**			
15	Other Revenue[2]	(4,770)	(62)	(4,832)
16	Interest on Security Deposits	24	-	24
17	2013 Excess Earnings	-	-	-
18	Energy Supply Cost Variance Adjustments	(5,772)	5,772	-
19	Other	1,887	(4,715)	(2,828)
20		(8,631)	995	(7,636)
21				
22	**2017 Revenue Requirement from Rates[3]**	665,246	17,332	682,578

[1] See *Section 5.3, 2016 and 2017 Revenue Requirements* for a summary of the Company's 2017 Revenue Requirements proposals.

[2] Excludes equity component of capitalized interest and interest on the RSA.

[3] Existing revenue requirement for 2017 excludes price elasticity impacts related to revenue of $2,803,000. The required revenue increase of $20,135,000 in 2017 (see Exhibit 9, page 2 of 2, line 1, column E) is comprised of $17,332,000 and price elasticity impacts related to revenue of $2,803,000 (see Exhibit 9, page 2 of 2, line 1, column D).

Newfoundland Power Inc.

2016 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	575,703	(375)	575,328
4	Preference Shares	8,948	-	8,948
5	Common Equity	474,060	2,255 [1]	476,315
6		1,058,711	1,880	1,060,591
7				
8	**Average Capital Structure**			
9	Debt	54.38%	(0.13%)	54.25%
10	Preference Shares	0.84%	0.00%	0.84%
11	Common Equity	44.78%	0.13% [1]	44.91%
12		100.00%	0.00%	100.00%
13				
14	**Cost of Capital**			
15	Debt	6.14%	0.01%	6.15%
16	Preference Shares	6.17%	0.00%	6.17%
17	Common Equity	7.96%	1.54% [1]	9.50%
18				
19	**Weighted Average Cost of Capital**			
20	Debt	3.34%	0.00%	3.34%
21	Preference Shares	0.05%	0.00%	0.05%
22	Common Equity	3.57%	0.70%	4.27%
23		6.96%	0.70%	7.66%
24				
25	**Return on Rate Base**			
26	Return on Debt	35,345	60	35,405
27	Return on Preference Shares	552	-	552
28	Return on Common Equity	37,752	7,505 [1]	45,257
29		73,649	7,565	81,214

[1] Reflects the Company's proposed return on common equity of 9.5 percent in 2016.

Newfoundland Power Inc.

2017 Return on Rate Base
($000s)

		Existing	Changes		Proposed
1					
2	**Average Capitalization**				
3	Debt	599,493	744		600,237
4	Preference Shares	8,948	-		8,948
5	Common Equity	493,739	2,146	[1]	495,885
6		1,102,180	2,890		1,105,070
7					
8	**Average Capital Structure**				
9	Debt	54.39%	(0.07%)		54.32%
10	Preference Shares	0.81%	0.00%		0.81%
11	Common Equity	44.80%	0.07%	[1]	44.87%
12		100.00%	0.00%		100.00%
13					
14	**Cost of Capital**				
15	Debt	6.11%	0.01%		6.12%
16	Preference Shares	6.17%	0.00%		6.17%
17	Common Equity	7.22%	2.28%	[1]	9.50%
18					
19	**Weighted Average Cost of Capital**				
20	Debt	3.32%	0.01%		3.33%
21	Preference Shares	0.05%	0.00%		0.05%
22	Common Equity	3.24%	1.02%		4.26%
23		6.61%	1.03%		7.64%
24					
25	**Return on Rate Base**				
26	Return on Debt	36,644	105		36,749
27	Return on Preference Shares	552	-		552
28	Return on Common Equity	35,661	11,454	[1]	47,115
29		72,857	11,559		84,416

[1] Reflects the Company's proposed return on common equity of 9.5 percent in 2017.

Newfoundland Power Inc.

2016 Revenue Requirement to Revenue From Rates Reconciliation
($000s)

		Existing A	Proposed B	Difference C	Price Elasticity[3] D	Proposed Increase[4] E
1	**Revenue From Rates**	661,775 [1]	669,685 [2]	7,910 [5]	805	8,715
2						
3	**RSA Charges[6]**	(6,281)	(6,276)	5	(6)	(1)
4						
5	**MTA Charges**	16,226	16,405	179	19	198
6						
7	**Total**	671,720	679,814	8,094	818	8,912

[1] 2016 Revenue from existing rates from Exhibit 7, page 1 of 2.
[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from Exhibit 7, page 1 of 2. Revenue from proposed rates reflect revenue from existing rates for January to June plus revenue from proposed rates for July to December.
[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).
[5] Exhibit 7 of the Application indicates a required increase in 2017 revenue from rates of $7,910,000 net of elasticity effects. This increase in revenue requirement includes the effect of the 2016 revenue shortfall amortization.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2015.

Newfoundland Power Inc.

2017 Revenue Requirement to Revenue From Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[3]	Proposed Increase[4]
		A	B	C	D	E
1	**Revenue From Rates**	665,246 [1]	682,578 [2]	17,332 [5]	2,803	20,135
2						
3	**RSA Charges**[6]	(6,306)	(6,277)	29	(30)	(1)
4						
5	**MTA Charges**	16,304	16,735	431	70	501
6						
7	**Total**	675,244	693,036	17,792	2,843	20,635 [7]

[1] 2017 Revenue from existing rates from Exhibit 7, page 2 of 2.
[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from Exhibit 7, page 2 of 2.
[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).
[5] Exhibit 7 of the Application indicates a required increase in 2017 revenue from rates of $17,332,000, net of elasticity effects. This increase in revenue requirement includes the effect of the 2016 revenue shortfall amortization.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2015.
[7] See Exhibit 10, Column E.

Newfoundland Power Inc.

2017 Average Customer Billing Impacts
($000s)

Forecast Impacts by Rate Class Under Existing and Proposed Rates
(includes July 1, 2015 RSA and MTA)

	Category	Existing Rates	Adjustment Due to Price Elasticity	Adjusted Existing Rates	Proposed Rates	Increase	Rate Increase
1		(A) [1]	(B) [2]	(C) [3]	(D) [4]	(E) [5]	(F) [6]
2							
3	1.1 Domestic	427,577	(2,584)	424,993	440,493	15,500	3.6%
4	1.1S Domestic Seasonal	2,198	-	2,198	2,278	80	3.6%
5	Total Domestic	429,775	(2,584)	427,191	442,771	15,580	3.6%
6							
7	2.1 General Service 0-100 kW	90,162	(245)	89,917	92,678	2,761	3.1%
8	2.3 General Service 110-1000 kVA	98,844	-	98,844	99,404	560	0.6%
9	2.4 General Service over 1000 kVA	37,426	-	37,426	38,576	1,150	3.1%
10	Total General Service	226,432	(245)	226,187	230,658	4,471	2.0%
11							
12	4.1 Street and Area Lighting	16,112	-	16,112	16,606	494	3.1%
13	Forfeited Discounts	2,925	(14)	2,911	3,001	90	3.1%
14							
15	**Total**	675,244	(2,843)	672,401	693,036	20,635	3.1%

[1] Column A is the forecast revenue plus RSA and MTA under existing rates, based on the 2017 test year sales forecast without elasticity impacts. See Exhibit 9, page 2 of 2, Column A.

[2] Column B is the elasticity impact on existing customer billings reflecting a 3.1% average increase in customer rates.

[3] Column C is the forecast customer billings under existing rates including elasticity impacts (Column A + Column B).

[4] Column D is the forecast customer billings under proposed rates including elasticity impacts. See Exhibit 9, page 2 of 2, Column B.

[5] Column E is the difference between forecast under proposed rates and that under existing rates adjusted for elasticity (Column D - Column C).

[6] Column F is the forecast rate increase (Column E / Column C).

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.26/month
Exceeding 200 Amp Service	$20.70/month	$21.26/month
Energy Charge - All kilowatt hours	10.573 ¢/kWh	10.959 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.26/month
Exceeding 200 Amp Service	$20.70/month	$21.26/month
Prompt Payment Discount	1.5%	1.5%
Domestic - Rate #1.1S		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.26/month
Exceeding 200 Amp Service	$20.70/month	$21.26/month
Energy Charge		
Winter Seasonal	11.526 ¢/kWh	11.912¢/kWh
Non-Winter Seasonal	9.276 ¢/kWh	9.662 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.26/month
Exceeding 200 Amp Service	$20.70/month	$21.26/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
G.S. 0-100 kW (110 kVA) - Rate #2.1		
Basic Customer Charge		
Unmetered	NA	$17.65/month
Single Phase	$21.93/month	$21.65/month
Three Phase	NA	$27.65/month
Demand Charge Regular	$9.10/kW - winter $6.60/kW - other	$9.34/kW - winter $6.84/kW - other
Energy Charge		
First 3,500 kilowatt-hours	10.534 ¢/kWh	10.861 ¢/kWh
All excess kilowatt-hours	7.791 ¢/kWh	8.033 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.345 ¢/kWh + B.C.C.
Minimum Monthly Charge		
Unmetered	NA	$17.65/month
Single Phase	$21.93/month	$21.65/month
Three Phase	$36.03/month	$33.65/month
Prompt Payment Discount	1.5%	1.5%
G.S. 110-1000 kVA - Rate #2.3		
Basic Customer Charge	$50.08/month	$50.41/month
Demand Charge	$7.86/kVA-winter $5.36/kVA-other	$7.88/kVA-winter $5.38/kVA-other
Energy Charge		
First 150 kWh per kVA of demand (max. 50,000)	9.156 ¢/kWh	9.213 ¢/kWh
All Excess kWh	7.286 ¢/kWh	7.329 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.345 ¢/kWh + B.C.C.
Minimum Monthly Charge	$50.08/month	$50.41/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
G.S. 1000 kVA and Over - Rate #2.4		
Basic Customer Charge	$85.13/month	$87.71/month
Demand Charge	$7.41/kVA-winter $4.91/kVA-other	$7.57/kVA-winter $5.07/kVA-other
Energy Charge		
First 75,000 kWh	8.605 ¢/kWh	8.870 ¢/kWh
All Excess kWh	7.041 ¢/kWh	7.258 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.345 ¢/kWh + B.C.C.
Minimum Monthly Charge	$85.13/month	$87.71/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

Street and Area Lighting Rates

		July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
Fixtures			
Sentinel/Standard			
High Pressure Sodium	100W	$16.78	$17.38
	150W	21.13	21.36
	250W	29.88	29.51
	400W	41.17	40.36
Post Top			
High Pressure Sodium	100W	$18.20	$18.80
Poles			
Wood		$7.24	$6.59
30' Concrete or Metal, direct buried		10.46	9.43
45' Concrete or Metal, direct buried		14.74	15.46
25' Concrete or Metal, Post Top, direct buried		7.99	7.01
Underground Wiring (per run)			
All sizes and types of fixtures		$12.80	$16.05

FIVE-YEAR CONSERVATION PLAN:
2016 – 2020

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND POWER
A FORTIS COMPANY

October 2015

CONTENTS

1.0 EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro ("Hydro") and Newfoundland Power have offered customer energy conservation programs on a joint and coordinated basis under the *takeCHARGE* brand since 2009. These programs provide a range of information and financial supports to help customers manage their energy usage.

The joint *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan") builds on this experience, and continues to reflect the principles underlying two previous joint, multi-year conservation plans developed by Hydro and Newfoundland Power (the "Utilities").[1] It reflects refinement of the opportunities identified in a recently updated conservation potential study (the "2015 CPS") through in-depth local market research and program cost benefit analysis.

The 2016 Plan represents both growth and evolution of the Utilities' joint customer energy conservation program portfolio. It includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. The approach outlined in this plan will remain flexible to address the changing provincial landscape, in terms of customer expectations, market conditions for energy efficient products, and electrical system costs. The 2016 Plan also addresses customer support and education, program planning and evaluation processes, as well as the Utilities' costs and cost recovery arrangements.

The total estimated energy savings for 2016 through 2020 are 883 GWh.[2] Total estimated costs through this period are $41.1 million.

[1] The *Five-Year Energy Conservation Plan: 2008-2013* was filed with the Board on June 27, 2008. The *Five-Year Energy Conservation Plan: 2012-2016* was filed on September 14, 2012.

[2] The energy savings indicated throughout the *Five-Year Energy Conservation Plan: 2016-2020* represent *gross* energy savings achieved by customers. These savings reflect all technologies installed by participating customers since program implementation. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program).

2.0 BACKGROUND

2.1 Planning Context

Hydro and Newfoundland Power have collaborated on customer energy conservation program planning and delivery for the past 8 years. The programs offered jointly under the takeCHARGE brand have included a variety of information and financial supports which help customers manage their energy usage. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service. Initiatives address conservation opportunities for customers in each sector: residential, commercial and industrial.

The Utilities' practice has been to refresh their joint strategic plans for customer conservation programming every three to four years. This ensures programs achieve long term goals while being responsive to changes in customer expectations, market barriers, technology developments, and economics. Current program offerings are based on the Five Year Energy Conservation Plan: 2012-2016 ("the 2012 Plan").

One of the key inputs into the 2016 Plan was the outcome of the Conservation Potential Study ("CPS"), completed by the Utilities in 2015. The CPS identified cost-effective energy and demand reduction measures, outlined general parameters for program development, and quantified achievable energy savings potential by sector and end-use. The results of the CPS are considered with the Utilities' experience and other factors in the local market to determine potential programs and energy saving targets for the 2016 Plan.

The Utilities' conservation planning is coordinated with overall planning for the electrical system. Significant changes to the Island Interconnected System are anticipated to occur in this planning period. Interconnection of the Muskrat Falls hydroelectric development is forecast for 2018 and will include the Island's first connection to the

North American grid. As a result, there is uncertainty with respect to the marginal cost of energy and capacity on the Island Interconnected System beyond 2017.

Schedule A provides the current forecast marginal cost of energy and capacity for 2015-2035.[3] The forecast indicates a decrease in the marginal cost of energy beginning in 2018. This effectively reduces the value of energy savings arising from customer energy conservation programming, and limits the types of programs that can be cost effectively offered.

Costs of electricity supply additions are expected to be incorporated into customer rates starting in 2018, putting upward pressure on customers' rates. This is expected to increase customers' motivation to conserve energy to manage their electricity costs. Also, the recent economic slowdown is anticipated to continue into this planning period and will influence customer behaviour with regards to conservation.

The 2008 and 2012 Five Year Conservation and Demand Management Plans, delivered jointly by the Utilities, had focused primarily on energy conservation. This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Generating Station) which justified such a focus. The events of recent winters have since brought to light issues with peak load and generation capacity on the Island Interconnected System which are anticipated to continue into this planning period. The 2016 Plan therefore considers demand management opportunities as well as energy conservation.

The Utilities have been offering some form of customer energy conservation programming since 1991, and have achieved significant energy savings over this time. The current forecast, particularly for insulation, anticipates diminishing returns. For example, the remaining potential for energy savings through insulation upgrades has

[3] The marginal costs used to determine cost effectiveness of the customer energy conservation programs are based on the most recent marginal cost forecast as projected by Hydro in February 2015. These estimates are currently under review by Hydro to incorporate the forecast interconnection with the North American grid. Once more current estimates are available, they will be incorporated in the screening process.

been impacted by changes to the National Building Code requiring basement insulation in new homes, as well as barriers to retrofitting many of the eligible existing homes. This is consistent with experience in other North American jurisdictions where utility programming has harvested the “low hanging fruit” and subsequently has moved on to address more challenging and costly opportunities.

Energy conservation programming has also been affected by technology advancements and changes to standards. Lighting product standards changes have effectively eliminated availability of incandescent bulbs for consumers. At the same time, LED technology has advanced and become more affordable and available. The pace of this change has been even faster than anticipated in the 2012 Plan. This is demonstrated by higher than projected uptake in the Utilities’ Instant Rebate component of the Small Technologies program.

The Utilities continue to work with the Provincial Government, through the Office of Climate Change and Energy Efficiency, regarding policy development for energy conservation and efficiency, and particularly potential impacts and approaches to building codes, product standards and broader market transformation objectives.

Many of the influences on the provincial energy conservation market can be seen in other North American jurisdictions. In recent years, many jurisdictions have experienced decreasing marginal costs of energy and increasing program costs due to maturing conservation programs. As a result, utilities and program administrators have revised their approach to economic analysis of energy conservation. The Utilities have conducted research on current economic evaluation practices. A summary of this research is provided in Schedule B. It indicates that Canadian jurisdictions use the Total Resource Cost (“TRC”) test as their primary benefit cost test for program screening, with the Program Administrator Cost test as a secondary test. Only one of the seven Canadian utilities researched used Ratepayer Impact Measure as a primary benefit cost test for program screening. In the United States, most jurisdictions follow similar practices with over 70% using TRC as the primary benefit cost test and 2% using Ratepayer Impact Measure for program screening.

2.2 Energy Conservation Programs

Based on the 2012 Plan, the Utilities have jointly offered customer energy conservation programs which provide both information and financial incentives to encourage customer installation of energy efficient technologies.[4] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table 1 shows, by sector, the portfolio of programs that have been offered under the 2012 Plan.[5]

Table 1
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat ENERGY STAR Window[6] HRV Block Heater Timer Small Technologies Isolated Systems Community Program	Lighting Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

4 Once installed, these more energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, an HRV has an estimated life of 15 years and will result in energy savings benefits throughout that period.

5 The Utilities also engage in demand management activities, including Newfoundland Power's Curtailable Service Rate Option and Hydro's interruptible load arrangements with its Industrial Customers.

6 The ENERGY STAR Window Program concluded at the end of 2014.

Schedule D summarizes the energy savings and costs for the customer energy conservation programs offered by the Utilities from 2009 through 2015.

Residential Programs

Table 2 provides a summary of residential customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).[7]

Table 2
Residential Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	2.5	7.1	18.6	28.5	38.4	51.5	65.7	**212.3**

The takeCHARGE residential programs are expected to result in aggregate energy savings of approximately 212.3 GWh by the end of 2015.[8]

Insulation Program

As a result of the updates to the National Building Code in 2012, several changes were made to the Insulation Program. New homes are no longer eligible and the minimum R-value requirements for existing homes have been increased. As well, the rebate structure was revised to provide a higher, easy-to-calculate rebate. Customers can receive an incentive of 75% of basement wall or ceiling insulation material costs up to $1,000, and 50% of attic insulation material costs up to $1,000.

7 Energy savings include savings arising from all technologies installed by all participants since program implementation. This reflects the fact that these technologies provide energy savings benefits for the customer throughout the life of the product.

8 Since implementation in 2009, there have been approximately 36,650 participants and over 638,000 at-the-cash rebates were provided on energy efficient products in the takeCHARGE residential customer programs.

Thermostat Program

High efficiency programmable and electronic thermostat replacements allow customers to conserve energy at relatively low cost and effort. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage.

ENERGY STAR Window Program

This program concluded at the end of 2014. After 5 years, and over 9,200 participating customers, the program had achieved its objective of making more efficient windows the standard in the local market.

Heat Recovery Ventilator Program

This program promotes the installation of high efficiency heat recovery ventilators ("HRVs"). HRVs have been widely used in new home construction in the province since the 1990s, to control humidity and air quality. The HRV program has experienced lower than projected participation since its launch in late 2013.[9] There has been improvement in 2015, and the Utilities will continue to monitor and evaluate this program in order to find opportunities to increase participation.

Block Heater Timer Program

Hydro provided giveaways and at-the-cash coupons for block heater timers to customers in Hydro's Labrador Interconnected System from 2012-2014. While vehicle engine block heaters are used extensively in this area, timers are rarely used. Instead of using electricity throughout the night, block heater timers allow vehicle owners to reduce the amount of time that electricity is used to warm the vehicle engine. Due to lack of participation this program was not continued past 2014 but commercial customers can take advantage of this technology through the Business Efficiency Program ("BEP") or the Isolated Systems Business Efficiency Program ("ISBEP").

[9] The Utilities have received feedback regarding low customer knowledge of home ventilation, with many customers being unaware of the purpose of a HRV in their home and how it can save energy. Also, there are complexities in the supply chain for acquiring a high efficiency HRV which can be problematic for potential participants.

Small Technologies

The small technologies program is supported by retail partners and appeals to a broad customer group as it does not involve a major home renovation. The program uses different marketing approaches for two different groups of energy efficient products.

The Instant Rebate component offers relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home.[10] Participation and energy savings results in the first two years of the program have exceeded the forecast in the 2012 plan. The Appliance and Electronics component offers incentives that are relatively higher value and available by mail-in and online application throughout the year.[11]

Isolated Systems Community Program

Following two pilot programs in 2010 and 2011, Hydro launched a full-scale, energy efficiency direct install program in 2012. The program includes direct installations of energy efficient products at no cost to homes and businesses.[12] The program also focuses on customer education and building capacity in the communities by hiring and training local representatives. These representatives work in their own communities to promote the program, provide information on energy use, and install the products.

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[10] Products include LED lighting, motion sensors, timers, dimmer switches, smart power strips and more.

[11] Products include energy efficient clothes washers, full-size refrigerators, full-size freezers and TVs.

[12] Products include low-flow showerheads and aerators, CFLs, smart power strips, and hot water tank and pipe insulation.

Commercial Programs

Table 3 provides a summary of commercial customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).

Table 3
Commercial Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	0.2	0.9	2.4	3.3	3.9	6.5	11.4	**28.6**

The takeCHARGE commercial programs will result in estimated aggregate energy savings of approximately 28.6 GWh by the end of 2015.[13]

Commercial Lighting Program

The Commercial Lighting Program targets reduced energy use through efficient lighting in commercial buildings, including high performance T8 and T5 fluorescent lighting and LED exit signs. This program has primarily been promoted through local lighting distributors by discounting lighting products at time of purchase.

The Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings from custom projects, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency improvement projects. It also includes rebates for specific measures on a per unit basis.

[13] Since implementation in 2009, there have been over 1,050 participants in the takeCHARGE commercial customer programs.

Isolated Systems Business Efficiency Program

This program is targeted toward commercial customers located in Hydro's isolated system communities. This custom program provides incentives based on the energy savings from efficiency improvement projects. This allows customers to implement energy efficient technologies that are suitable for their specific buildings, equipment and operations.

Industrial Programs

Table 4 provides a summary of industrial customer energy savings achieved through Utility customer energy conservation programs from 2009 through 2015(F).

Table 4
Industrial Program Energy Savings
2009 through 2015(F)
(GWh)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Energy Savings	-	-	0.2	3.3	3.3	25.6	25.6	58.0

The takeCHARGE Industrial Energy Efficiency program will result in estimated aggregate energy savings of approximately 58.0 GWh by the end of 2015.[14]

The Industrial Energy Efficiency Program is a custom program that responds to the unique needs of Hydro's transmission level industrial customers. This program provides financial support for engineering feasibility studies of efficiency projects and for project implementation costs. The Industrial program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011 and the last being submitted in 2013. No projects were completed in 2013 as focus was put on feasibility studies for work to be completed in 2014. The program then underwent an assessment by an external third party in 2014 and was re-launched as a full program in 2015.

[14] Since implementation in 2009, there have been 5 projects completed under the takeCHARGE Industrial Energy Efficiency Program.

2.3 Education & Support

The Utilities continue to provide energy efficiency education and support to customers through a variety of channels, which include a joint website, outreach activities, school presentations and partnerships with other organizations.

Table 5 shows the number of customer-initiated contacts with the Utilities for energy conservation information from 2010 through 2015 YTD.

Table 5
Customer Contacts for
Energy Conservation Information

	2010	2011	2012	2013	2014	2015YTD
Contact Centre Inquiries	11,704	12,624	9,793	9,630	10,830	5,328
Website Visits	52,013	72,996	49,202	76,278	186,003	197,973

The majority of customers chose electronic means of communication with the Utilities to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information. Customer visits to the takeCHARGE website grew by 144% from 2013 to 2014. Activity in the first eight months of 2015 shows continued growth, with approximately 80% of website visits via a mobile device. This increase is related to increased promotion, changes to existing programs, and addition of new programs.

The Utilities have participated in an average of 214 community outreach events each year since 2012. This included presentations to retailers and suppliers, senior citizens, trade allies and other groups. takeCHARGE information booths were displayed at home shows, trade fairs, and retail stores across the province. The Utilities also offer a number of outreach events, such as the annual takeCHARGE of Your Town Challenge and Energy Efficiency Week. Through these outreach activities, members of the takeCHARGE team assisted customers with their energy efficiency questions, while raising awareness of energy conservation and the takeCHARGE rebate programs.

Over the last three years the takeCHARGE *Kids in Charge* K-I-C Start school program, has provided energy efficiency and conservation education support to students throughout Newfoundland and Labrador. This has included delivering in classroom presentations and an annual contest for primary and elementary students. In 2014, takeCHARGE partnered with the Provincial Office of Climate Change and Energy Efficiency to extend this program through the Hotshots pilot program.[15] As a result, in 2014-15 school year, over 11,000 students in 106 schools throughout the province participated in 448 presentations about energy conservation.

Trade allies play an integral role in helping customers make knowledgeable decisions regarding energy conservation and related home improvements. Retail partners display information about takeCHARGE programs and energy efficiency products in their stores and in flyers, as well as during special promotional events.[16] Similarly, the Utilities are continuing to grow a network of business to business service providers and suppliers that support the commercial and industrial sectors.[17]

The Utilities have also developed partnerships with a variety of other organizations that share common goals for the province's conservation market, including the Association of Newfoundland and Labrador Realtors, the Canadian Home Builders Association, Newfoundland and Labrador Housing Corporation, and the Canadian Mortgage and Housing Corporation.

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[15] Through the HotShots pilot, the Province provided funding and support for additional in-class presentations, curriculum linked teacher materials, and a contest for high school students.

[16] The Utilities continue to work with over 160 retail store partners, 11 manufacturers/distributors, and approximately 50 HRV installers.

[17] These include lighting equipment manufacturers and distributors, electrical and HVAC contractors, and engineering firms.

Table 6 shows costs for education and support for the period 2009-2015(F).

Table 6
Conservation Education & Support
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Education	666	486	428	426	501	647	693	3,847
Support	236	206	219	222	186	174	158	1,401
Total	**902**	**692**	**647**	**648**	**687**	**821**	**851**	**5,248**

2.4 Planning & Evaluation

Planning

The focus of the Utilities' CDM planning process is to develop a 5-year plan for the implementation of comprehensive customer energy conservation and demand management programs around the technologies that were determined to have conservation potential in the provincial market. The completion of the CPS in 2015 effectively initiated the development of the 2016 Plan.

Programs are developed and revised through consultation with the various market stakeholders, such as government, trade allies and local interest groups, to gather feedback on program delivery strategy.

Table 7 shows costs for conservation planning for the period 2009-2015(F).[18]

Table 7
Conservation Planning
Costs 2009-2015(F)
($000s)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**	**Total**
Planning	401	429	509	404	462	958	1,202	4,365

Variations in annual conservation planning costs primarily reflect the periodic nature of the Utilities' program planning and research activities.

Research

In 2013, the Utilities completed a joint Commercial Facility Equipment Inventory ("CFEI") on 54 commercial facilities.[19] This research provided information on how commercial customers use electricity, through an inventory and analysis of all mechanical and electrical equipment in each facility.[20] This data was used as a direct input into the CPS conducted in 2015.

In 2014, Newfoundland Power and Hydro jointly conducted a survey to gather information regarding electricity end uses in the residential sector. The information gathered was used to assess potential electricity savings opportunities, and was used as a direct input into the current planning cycle. These results are also being taken into account in making adjustments to the *takeCHARGE* programs. For example, because

18 Conservation planning costs include costs related to surveys and research, development of the potential study and the five-year plan, and general administration.

19 The CFEI was completed by CBCL Limited, a consultant that conducted on-site facility audits for participating commercial customers. CBCL Limited is a leading employee owned multidisciplinary engineering and environmental consulting firm in Atlantic Canada.

20 The CFEI found, for example, that the food retail sector are the largest users of electricity on a square footage basis of the customers audited, followed by the manufacturing/fish processing sector.

of survey findings regarding the prevalence of CFLs, these have been removed from the Instant Rebates Program beginning in the fall of 2015.[21]

Newfoundland Power completed research on ductless mini-split heat pumps ("MSHP") from 2013 to 2015. The objectives of this research were to assess the current MSHP market in Newfoundland, the use of the MSHP as a supplementary heat source and the potential impact of MSHPs on the electricity system. The results indicate that MSHP are more efficient and do save energy compared to electric baseboard heat.[22] This analysis also shows that there is not likely to be peak demand reduction on the electricity system from installation of MSHPs.[23] Customer demand for MSHP products has grown significantly in recent years and continues to be strong. However, there are issues with availability of qualified installers and customer understanding of product quality requirements.

In the fall of 2014, Newfoundland Power launched a pilot program to assess the economic, market, and technical feasibility of direct load control to reduce overall peak demand. This pilot was initiated in response to the constraints on system capacity that became evident after the events in January of 2013 and 2014. The pilot involved controlling hot water tanks in approximately 500 customer homes in Paradise and Mount Pearl. Demand reduction achieved by the direct load control events on average was 0.6 kW per participant, and for events that included all participants, approximately

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21 Customers were asked what types of lighting they use in areas of their house where they spend the most time: 63% reported that they use incandescent bulbs, 53% CFLs, and 18% LEDs (multiple responses allowed). In another question, 31% of respondents claimed to have changed all their bulbs to more energy efficient types, and 45% indicated that they have begun to change to more energy efficient types.

22 Approximately half of the homes in the study recorded energy savings after installation of the MSHP. In these homes, electricity usage declined by an average of 5,300 kWh or 19% per year, with savings ranging from 7% to 50%. The remaining homes recorded an increase or no change in energy usage. This appears to reflect factors such as heating of additional living space, fuel switching, or operational issues with the MSHP.

23 Savings at time of system peak are dependent on a number of factors such as the efficiency and defrost cycle of the MSHP system, and temperature. A high efficiency MSHP may be capable of providing peak savings in warmer parts of the province but not in colder regions, while a less efficient MSHP may not be capable of providing peak savings in any region. On colder weekdays, the study observed little difference in the load profile of the MSHP homes vs. electric baseboard homes, and occasionally the MSHP homes' peak load was slightly higher.

298 kW of demand reduction was achieved. The Pilot results also indicate that a full scale provincial program does not meet the economic requirements.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project, which is supported by the Utilities and administered by Hydro, began in September 2014 and aims to assess whether real time display of energy use has a positive effect on electricity conservation behavior. The pilot involves approximately 750 customers: 250 with an in-home display device, 250 with an in-home display device as well as electricity conservation information in a monthly mail out, and 250 with only the electricity conservation information. Monitoring of participants will continue until January 2016 and the final report will be submitted to Government by end of March 2016.

Evaluation

The customer energy conservation programs are continuously evaluated by the Utilities on their energy savings, market impacts and delivery process effectiveness. Additional review by external third party evaluators has also been conducted. Program evaluation findings are used to refine program design and implementation details on an ongoing basis, as well as support further planning.

For example, the third party residential program evaluation in 2013 found that two-thirds of windows sold in the province were ENERGY STAR, which supported the Utilities' decision to conclude the ENERGY STAR Windows Program.[24]

Economic and energy savings evaluation of the customer energy conservation programs is performed annually. Program participants are required to provide certain information on program rebate applications. This information ranges from technical data, such as the R-value of installed insulation, or efficiency rating of a HRV to the type of heating in the home and its geographic location. Analysis of this data allows the

[24] The 2013 residential program evaluation was conducted DNV GL- Energy, headquartered in Burlington, Massachusetts, and specializing in evaluating programs that promote energy efficiency, demand response, and distributed generation.

Utilities to accurately estimate the energy savings for each program and perform industry standard economic cost-benefit tests.

2.5 CDM Costs & Cost Recovery

Table 8 provides a summary of the customer energy conservation program and general costs of the Utilities from 2009 through 2015(F).[25]

Table 8
Conservation Costs
2009 through 2015 (F)
($000s)

	2009	2010	2011	2012	2013	2014	2015F	Total
Programs								
Residential	1,386	2,322	3,473	3,436	3,921	4,277	5,188	24,003
Commercial	79	95	216	214	355	926	1,388	3,273
Industrial	57	226	103	173	89	1,244	19	1,910
Total Programs	1,522	2,643	3,791	3,823	4,365	6,447	6,595	29,186
General	1,303	1,121	1,156	1,052	1,149	1,779	2,054	9,614
Total	**2,825**	**3,764**	**4,947**	**4,875**	**5,514**	**8,226**	**8,649**	**38,800**

The Utilities' costs related to conservation programs have increased from approximately $2.8 million in 2009 to $8.6 million in 2015. This primarily reflects the addition of new customer energy conservation programs in 2013, specifically the Small Technologies Program and the Business Efficiency Program. This also reflects the increased levels of customer participation and rebates related to the joint takeCHARGE program portfolio. The expansion of customer programs has also resulted in increasing energy savings.

[25] This cost summary does not include (i) costs related to programs offered independently by the Utilities prior to June 2009; (ii) costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management); and (iii) costs related to Hydro's interruptible service arrangements with its Industrial Customers.

Details of the Utilities' customer energy conservation program and general costs are provided in Schedule C.

The Utilities each bear the costs related to the provision of customer energy conservation programming in their own service territory. General conservation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising, are split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[26]

Cost Recovery

Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through the annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred.

Hydro's current customer rates, as approved by the Board in Order No. P.U. 8 (2007), include recovery of approximately $0.4 million in costs related to management and planning of conservation programming. In each year from 2009 to 2014, inclusive, Hydro has deferred recovery of direct program costs related to the expansion of customer energy conservation programming under the 2008 Plan and 2012 Plan.[27] As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014,

[26] This approach to division of jointly incurred costs reflects the proportion of customers served by each utility.

[27] The deferred recovery of these costs in 2009, 2010, 2011, 2012, 2013, and 2014 were approved by the Board in Order Nos. P.U. 14(2009), P.U. 13(2010), P.U. 4(2011), P.U. 3(2012), P.U. 35(2013), and P.U. 43(2014), respectively.

the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale, with participation by Board Hearing Counsel, have engaged in negotiations with Hydro. As a result, these parties agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."[28]

3.0 PLAN: 2016-2020

3.1 Conservation Potential & Program Selection

The programs included in the 2016 Plan have been selected based on a number of considerations. Opportunities identified in the 2015 CPS are a key input and these have been further assessed by the Utilities in terms of engineering, market and economic viability. Consideration has also been given to the experience of the Utilities and others in the local marketplace, feedback from customers, as well as experience shared from other Canadian jurisdictions.

Conservation Potential Study

In June 2015, a comprehensive study was completed of electricity conservation and demand management potential for the province.[29] This Conservation Potential Study estimated the potential for electrical energy and demand savings by sector and by electricity system from 2015-2029. It also identified specific technologies available to assist in achieving that potential. The CPS essentially provides a framework, consistent with current North American practices, within which to assess conservation programming. The findings enabled the Utilities to quickly focus on cost effective technologies and begin assessment of market characteristics to guide program concept development.

[28] Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015.

[29] ICF International (previously called Marbek) conducted Conservation Potential Studies for the Utilities in 2007 and 2015. ICF International is a leading environmental and energy management consultancy and has extensive experience conducting Conservation Potential Studies in Canada.

Electrical system marginal costs of supply are used in the CPS to screen the economic viability of more efficient technologies.[30] For the current CPS, these costs were based on the most recent marginal cost forecast as projected by Hydro in February 2015.[31] These estimates are currently under review. Once Hydro's marginal cost study is completed, the CPS results will be reassessed. If such a review results in changes to the list of cost effective technologies with conservation potential, these will be considered in future updates to the 2016 Plan.

Figure 1 shows the baseline provincial energy usage forecast which was input to the 2015 CPS (the reference case), and the upper and lower achievable potentials estimated by the Potential Study.[32]

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[30] Technologies are considered to be economically viable when the cost of saving one kWh or kW of electricity is equal to, or less than, the marginal cost of supplying the electricity.

[31] The 2015 CPS included an analysis of the sensitivity of potential technologies to changes in marginal costs. The analysis was based on a range of + 30% to – 10% of the February 2015 forecast marginal costs. It indicated a modest level of variability in technology viability and resulting conservation results. Please see CPS, section 7.5 Energy Efficiency Supply Curve, filed with the Board September 15, 2015.

[32] The reference case is based on the provincial energy usage forecast from 2014. After this study was completed the energy usage forecast decreased due to the economic downturn, mainly in the industrial sector. The achievable potential is defined as the portion of the economic conservation potential that is achievable through utility interventions and programs given institutional, economic and market barriers. The upper achievable potential is considered to be the best case scenario with all market barriers removed, such as capital cost and product accessibility. The lower achievable potential is considered a business as usual scenario with the existing market barriers remaining in place.

Figure 1
Conservation Potential Study Results
Provincial Electrical Consumption
2014-2029

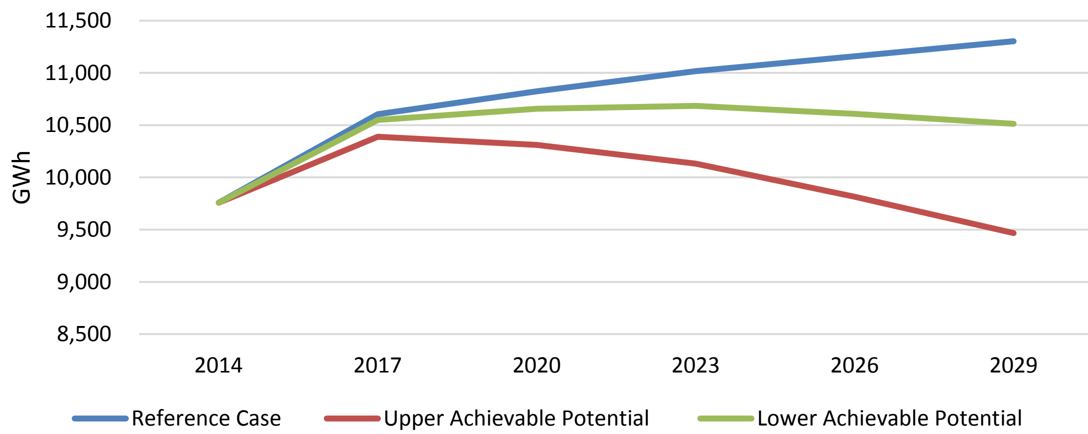

Figure 1 shows that, over time, the cumulative effects of implementing cost effective efficient technologies can significantly reduce forecast growth in electricity usage.[33]

Figures 2 and 3 show the results of the CPS regarding achievable demand reduction potential from energy efficiency measures ("Energy Efficiency") and from demand response specific measures ("Demand Response") by 2020.[34]

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[33] At the end of the first estimation interval, in 2017, the CPS shows a range of 55 GWh for the lower achievable potential savings and 215 GWh for the upper achievable potential savings. This compares with annual savings of approximately 116 GWh currently estimated in the Plan for the same timeframe.

[34] The Commercial and Industrial sector includes Hydro's large transmission level Industrial customers as well as Newfoundland Power's general service customers.

Figure 2
Lower Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)

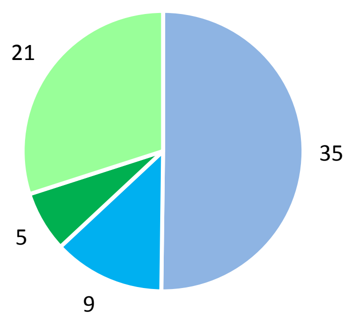
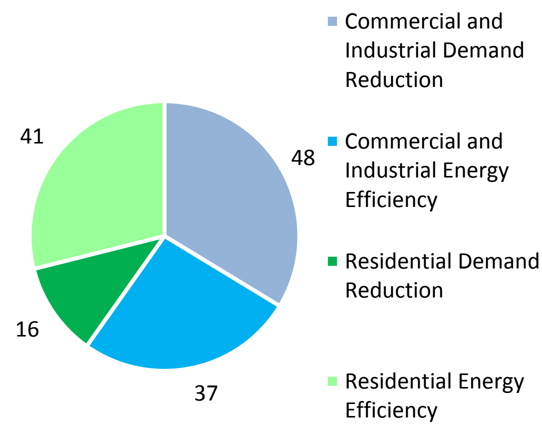


Figure 3
Upper Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)



Figures 2 and 3 show 70 MW for the lower potential and 142 MW for the upper potential demand reduction on the Island Interconnected System.[35] Installation of energy efficiency measures that reduce consumption during times of peak demand account for approximately 43% and 55% of the lower and upper achievable demand reduction, respectively, by 2020.[36]

The majority of the demand reduction potential was identified in the Commercial and Industrial sectors. Specifically, the Industrial sector represents about 87% and 74% of the total lower and upper achievable demand reduction, respectively. The demand reduction technologies identified through the CPS as having the most potential included curtailable load arrangements with commercial and industrial customers and direct load control of residential hot water tanks.

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35 21+35+9+5=70 and 41+16+37+48= 142
36 (21+9)/70=43% and (37+41)/142=55%.

Selection

The technologies that passed the economic screening of the CPS were reviewed in detail to assess their possible inclusion in the 2016 Plan. Local market research was conducted to identify barriers to broader adoption of more efficient technologies, such as capital cost, market availability and awareness. This included consultation with market stakeholders and trade allies, as well as discussions with other utilities.

Once existing market barriers were identified, a program strategy was then developed to attempt to overcome those barriers. Costs associated with the program were considered and the cost effectiveness of the program determined.[37] This more detailed review of program costs and benefits can cause a technology that had passed economic screening in the CPS to fail the economic tests required of CDM programs.

Economic Screening

The Utilities' economic screening of the customer energy conservation programs has previously required a positive result for both the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") cost-benefit tests.[38] Recent research indicates Canadian and U.S. utility practice has changed to focus on the TRC and Program Administrator Cost ("PAC") tests.[39]

The Utilities recommend adoption of the TRC as the primary means of program economic screening, and the PAC as a secondary means. This is consistent with current North American practice, and is appropriate based on the electrical system marginal costs and program objectives in this jurisdiction. Based on this recommendation the programs included in the 2016 Plan passed economic screening

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[37] Program cost estimates include marketing, delivery and administration, incentives, measurement and verification, and evaluation.

[38] In Order No. P.U.7 (1996-97), the Board required customer conservation programs to be evaluated with respect to rate impact, as well as the total resource costs. The Utilities' have interpreted this Order to require a TRC of 1.0 and a RIM of 0.8 as described in *Newfoundland Power Inc. – 2009 Conservation Cost Deferral Application, Section 2: Proposed Customer Program Portfolio* filed with the Board October 29, 2008.

[39] See Section 2.1, page 4, and Schedule B.

based on the TRC and PAC.[40] The Utilities' will continue to monitor changes to economic screening practices to appropriately reflect evolving program characteristics and electrical system costs.

3.2 Conservation & Demand Management Programs

The 2016 Plan builds on the outcomes of the 2012 plan as well as the experience of the Utilities. Programs included in the 2016 Plan address conservation opportunities in all three sectors: residential, commercial, and industrial. The 2016 Plan includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. These conservation programs are broadly consistent with programs offered by utilities in other jurisdictions.

Table 9 shows, by sector, the portfolio of programs to be offered under the 2016 Plan.

Table 9
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat HRV Small Technologies Isolated Systems Community Program Benchmarking	Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

[40] Application of the RIM test would result in elimination of a number of programs, including Benchmarking, HRV, and Small Technologies.

Residential Programs

Insulation, Thermostat and HRV Programs

These existing joint incentive programs primarily target space heating energy savings, and will continue to be offered as part of the 2016 Plan. The remaining eligible market for the Insulation and Thermostats programs has been declining in recent years. The HRV program has had limited participation due to barriers related to customer understanding and market complexity. These programs will be continuously evaluated to ensure program cost effectiveness.

Small Technology Program

The jointly offered Small Technologies program will continue to use different marketing approaches for the two different groups of energy efficient products.

The Instant Rebate component will continue to offer relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home. As part of the 2016 Plan, Instant Rebates will include additional technologies.[41] It is anticipated that this component will end during 2018 as LED lighting becomes the norm in the residential lighting market.[42] Most of the energy savings benefits in this program are related to customers' early adoption of LED lighting from less efficient technologies, and energy savings from non-lighting products are not expected to be sufficient to offset the program delivery costs.

Incentives for the Appliance and Electronics component will continue to be available through 2017. At that time, anticipated reductions in marginal costs on the electricity system will effectively reduce the value of energy saving benefits, causing the program to fail economic screening.

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[41] As part of the 2016 Plan, Instant Rebates will include additional technologies, such as faucet aerators, door bottom weather stripping, door adhesive weather stripping, window insulation kits, electrical outlet gaskets, and caulking.

[42] The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Isolated Systems Community Program

The existing format for this program will continue to be offered to customers in Hydro's isolated system communities through 2017. Information and feedback collected in 2014 and 2015, particularly for the direct install component, will be used to evaluate and plan for the Isolated Systems Community Program beyond 2017.

An Appliance Retirement component will be added to this program beginning in 2016, targeting at least one community. Older inefficient appliances will be removed from participating homes and routed for appropriate disposal.[43]

Benchmarking

This new joint program will promote customer behaviour changes to encourage more efficient energy use. Benchmarking involves using social norms to encourage neighbourly competition to reduce electricity consumption. This program will include comparison of participant households' energy consumption with their energy history and that of similar households. Participants will also receive personalized home energy reports that provide household specific electricity usage information and savings tips to help them reduce energy use and lower their electricity bills. This program will be available to customers from 2016 to 2019.

Commercial Programs

Lighting Program

Beginning in 2016, existing commercial lighting program products will become prescriptive rebates under the Business Efficiency Program, including the fluorescent high bay, high performance T8 fluorescent lamp and LED exit sign. This change will allow for more specific marketing initiatives and increased awareness of the rebates available for these technologies.

[43] This component will be evaluated to determine whether a broader program would be cost effective.

Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts have become the market standard. Industry partners indicate that approximately 55% of ballasts sold in the province in 2014 meet the program efficiency criteria.[44]

Business Efficiency Program

The Business Efficiency Program, offered jointly by the Utilities, will continue to provide custom and prescriptive incentives to commercial customers for energy efficiency improvements. Continued growth in customer participation and energy savings are anticipated for this program. The Utilities will increase the customer education and awareness component of this program to include sector-based identification of energy efficiency opportunities. New technologies will also be added to the program's list of prescriptive incentives.[45]

Isolated Systems Business Efficiency Program

This program will continue through 2020, and will be offered to Hydro's commercial customers located in isolated system communities. The program will continue to provide incentives based on the energy savings of customer projects, similar to the Business Efficiency Program.

Industrial Programs

Industrial Energy Efficiency Program

Through 2020, this customized program will continue to offer support and financial incentives based on energy savings for retrofit of industrial process equipment for Hydro's transmission level industrial customers.[46]

[44] Note that U.S. Federal Regulations are now equivalent to this ballast efficiency specification.
[45] These include: LED screw-in lamps, high bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems, and low flow pre-rinse spray valves.
[46] The Industrial Energy Efficiency Program's cost effectiveness and potential energy savings will be evaluated on a year to year basis.

Customer Energy Savings

Table 10 shows forecast customer energy reduction estimates for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 10
2016 Plan Energy Reduction Estimates
2016 through 2020
(GWh)

	2016	2017	2018	2019	2020	Total
Residential	80.4	102.7	118.1	123.5	111.7	536.4
Commercial	18.7	27.6	37.5	48.6	61.4	193.8
Industrial	30.6	30.6	30.6	30.6	30.6	153.0
Total	129.7	160.9	186.2	202.7	203.7	883.2

The programs in the 2016 Plan will result in estimated aggregate customer energy savings of approximately 883.2 GWh from 2016 through 2020. Customer energy savings are forecast to increase annually through 2020, due to expansion of the program portfolio and the addition of program technologies for the residential and commercial sectors.

Several program offerings are expected to be concluded during the planning period. These include the Small Technologies program and the Benchmarking program. Design of alternate programming for the residential sector is anticipated through the Utilities' program planning in 2018.

Demand Management

The previous conservation and demand management plans have focused primarily on energy conservation.[47] However, the Utilities' customer energy conservation programs have resulted in quantifiable demand savings.

The technologies identified through the CPS as having the most potential for demand reduction included direct load control of residential hot water tanks and curtailable load arrangements with commercial and industrial customers. Recent research has identified issues with the cost effectiveness of residential load control on the Island Interconnected System. As a result, this measure is not included in the 2016 Plan.[48] The Utilities will continue to pursue curtailment opportunities with their larger customers.[49]

A new component will also be added to the Business Efficiency Program ("BEP") to include a custom incentive for demand reduction measures that are economically viable and that provide measureable demand reduction during peak times.[50]

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47 This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Station) which justified such a focus.

48 Although residential load control on the Island Interconnected System does not make economic sense, Hydro's isolated communities served by diesel generation have higher marginal costs which may make the program cost effective.

49 Hydro currently has interruptible load arrangements with its Industrial Customers which have potential for more than 90 MW of capacity assistance. Newfoundland Power currently has 16 customers participating in its Curtailable Rate Option, providing 10.4 MW of potential load reduction.

50 More information on the custom demand component of the BEP can be found in Schedule C.

Table 11 shows forecast customer demand reduction estimates for the customer energy conservation programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 11
2016 Plan Demand Reduction Estimates
2016 through 2020[51]
(MW)

	2016	2017	2018	2019	2020	Total
Residential	3.3	4.7	5.0	4.3	1.4	18.6
Commercial	2.1	2.0	2.3	2.5	2.8	11.7
Total	5.4	6.7	7.3	6.8	4.2	30.3

The Utilities' takeCHARGE customer energy conservation programs are forecast to achieve approximately 30.3 MW in peak demand reduction through 2020. This demand reduction will occur annually for the life of the installed technologies.[52]

[51] Hydro does not forecast demand reduction for their transmission level industrial customers.
[52] For example, a customer who installs basement insulation in 2014 will achieve approximately 0.9 kW of annual peak demand reduction for the next 20 years.

2016 Plan Program Costs

Table 12 shows forecast costs for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 12
2016 Plan Program Costs Estimates
2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Residential	5,987	6,308	4,540	3,048	2,042	21,925
Commercial	1,628	1,906	1,933	2,258	2,301	10,026
Industrial[53]	667	10	10	10	10	707
Total	8,282	8,224	6,483	5,316	4,353	32,658

The Utilities' costs related to programs in the 2016 Plan are forecast to be approximately $32.7 million over the five-year planning period. Forecast changes in program costs primarily reflect the expansion of programs and additional technology offerings anticipated from 2016 to 2018, and the conclusion of certain programs through the planning period.

3.3 Education & Support

The Utilities' customer education and support activities will continue to evolve to support changes in customer energy conservation programs and in the broader conservation market. The Utilities will continue to provide customer support and be responsive to customer expectations. Current activities, including customer outreach events, the takeCHARGE website and partnerships with industry stakeholders will be key elements of customer education.

[53] Forecasted Industrial program costs after 2016 are associated with program promotion and customer engagement. Given the small number of transmission level customers in the province, there is a high degree of uncertainty for participation in the program year to year. The forecasted amounts after 2016 will increase if customers avail of the program for feasibility assessments or incentives for energy efficiency retrofits. Projects will continue to be screened based on cost effectiveness to ensure the program remains above minimum economic thresholds.

The Utilities' educational initiatives will be expanded to include a program promoting mini-split heat pumps. The program components will include financing, education and marketing initiatives directed towards customers, and direct engagement with certified installers and suppliers. A marketing campaign will be launched to raise customer awareness of the benefits of this technology, how to choose a high quality product, as well as the necessity of having the system installed by qualified contractors. The eligibility criteria for on-bill financing of these systems will encourage the installation of high efficiency units, installed by qualified contractors.[54]

The Utilities will continue to build upon their experience offering the takeCHARGE K-I-C Start School Program. Marketing will continue to build awareness of the program amongst school boards and teachers. Teaching aids will be developed and be made available on the takeCHARGE website to assist in furthering conservation education after presentations are conducted. Updates will also be made to strengthen the message of conservation for younger students, and awareness-building contests will be offered for all age groups.

Table 13 shows forecast costs for conservation education and support for the period 2016 to 2020.

Table 13
Conservation Education & Support
Costs 2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Education	770	791	827	851	873	4,112
Support	171	175	181	184	191	902
Total	941	966	1,008	1,035	1,064	5,014

[54] Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016.

3.4 Planning & Evaluation

Planning

The 2016 Plan incorporates research and analysis required for the next iteration of multi-year conservation portfolio planning by the Utilities.

Table 14 shows forecast planning costs included in the 2016 Plan.

Table 14
Conservation Planning Costs 2016-2020(F)
($000s)

	2016	2017	2018	2019	2020	Total
Planning	527	596	767	863	644	3,397

Variability in annual planning costs reflects the Utilities' multi-year planning cycle for customer conservation programs.

The Utilities anticipate development of the next multi-year plan for customer energy and demand conservation programming in 2018. Further clarity regarding electrical system cost dynamics is expected to be a factor in the next planning cycle.[55] Further assessment and adjustments to the programming contained in the 2016 Plan may also be required within the next three years as marginal cost forecasts are updated.

Research

The next update of the study of conservation potential in the province is being planned for 2020. In advance of this study, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For the residential sector, customer surveys will gather details on

55 An updated marginal cost study is expected to be a key input to the next conservation plan in 2018 and the next CPS in 2019-2020.

the type of electrical equipment that customers have in their homes, as well as their energy-related behaviour and motivation. Research for the commercial sector will include on-site facility audits to collect data on mechanical and electrical equipment being used.

The residential lighting market will be evaluated in 2017 to determine whether the Small Technologies program should continue. This research is expected to include a socket saturation study, with onsite inventories, as well as customer surveying. This will provide the Utilities with detailed data regarding the remaining potential for energy efficient lighting replacements.

Hydro is currently investigating the implementation of an Isolated System Direct Load Control Pilot in the community of Postville, Labrador.[56] The community of Postville is served by diesel generation. The objective of this pilot will be to reduce the peak load in the community and defer investment in electrical system upgrades. The Utilities will also continue to coordinate conservation planning with electrical system planning, and will evaluate potential for conservation initiatives targeted in specific areas or communities that may provide a lower-cost alternative to electrical system upgrades.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project is ongoing and the final report will be submitted to Government by end of March 2016. The results of this pilot project will be used to assess whether this type of technology may be considered as part of future energy conservation programming.

During this planning period, the Utilities will also monitor developments in North American practices for economic evaluation and screening of conservation programs.[57]

[56] The pilot will involve commercial and residential customers. It will include installing load controllers on hot water tanks, and commercial electric heating circuits, for commercial customers. Load controllers will only be activated during maximum system peak events. The customers that participate will receive incentives such as credits at the local store in Postville.

[57] While reliance on the TRC and PAC tests for primary economic screening is currently the norm in North American jurisdictions, modifications to the TRC methodology are being considered in a number of cases. These modifications primarily involve inclusion of customers' non-energy benefits from efficiency upgrade projects.

Evaluation

The customer program portfolio will continue to be evaluated in terms of its energy savings, market impacts and delivery process effectiveness. Additional review by third party evaluators is expected, reflecting the expanded program portfolio and delivery methods.[58] Program evaluation findings will be used to refine program design and implementation details on an ongoing basis, as well as support further planning.

Specific evaluation objectives in the 2016 Plan are to monitor market saturation of particular technologies as well as cost effectiveness of the programs. For example, the Instant Rebates component of the Small Technologies program will be evaluated and an exit strategy designed based on research into the pace and impact of LED sales growth in the local lighting market.

Similarly, the Utilities will continue to closely monitor the Insulation, Thermostat and HRV programs. These programs have unique challenges and barriers to program participation.[59] Evaluation of these programs will ensure they continue to satisfy cost effectiveness requirements.

In the case of new program introductions, post-implementation evaluations will be conducted within 12 months of program launch to ensure full assessment of program design assumptions, as well as marketing and delivery process effectiveness.

58 Evaluation costs are primarily reflected in the costs for each specific program.

59 For the Insulation and Thermostat Programs, these barriers primarily reflect the inherent difficulty in renovating existing living spaces and the remaining market being increasingly hard-to-reach. For the HRV program, this reflects the low level of customer understanding and slow adoption by the supply chain.

3.5 Costs & Cost Recovery

Table 15 provides a summary of the Utilities' customer energy conservation program and general costs from 2016 through 2020.[60]

Table 15
Conservation Costs
2016 through 2020
($000s)

	2016	2017	2018	2019	2020
Program					
Residential	5,987	6,308	4,540	3,048	2,042
Commercial	1,628	1,906	1,933	2,258	2,301
Industrial	667	10	10	10	10
Total Programs	8,282	8,224	6,483	5,316	4,353
Education	770	791	827	851	873
Support	171	175	181	184	191
Planning	527	596	767	863	644
Total General Costs	1,468	1,562	1,775	1,898	1,708
Total	9,750	9,786	8,257	7,214	6,061

Costs related to the customer energy conservation programs outlined in the 2016 Plan are forecast to be $9.8 million in 2016 and 2017.[61] This increase primarily reflects the addition of a new program, and enhanced program technology offerings. Costs begin to decrease in 2018 from $8.3 million to $6.0 million in 2020. This decrease primarily reflects the conclusion of the Small Technologies program in 2018 and the conclusion of the Benchmarking program in 2019.

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60 This cost summary does not include costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management) and costs related to Hydro's interruptible load arrangements.

61 All customer energy conservation programs outlined in the 2016 Plan are cost effective, and are justified on a cost of service basis.

Schedule E provides a summary of forecast energy savings, cost estimates and cost effectiveness analysis results for the programs in the 2016 Plan.[62]

Cost Recovery

The Utilities propose conservation cost recovery based on amortizing customer energy conservation program costs over seven years.[63] The amortization of program costs over a seven-year period is considered appropriate because of the extended nature of the energy savings benefits provided by program technologies.

The Utilities' annually recurring general conservation costs would continue to be expensed as incurred.[64]

4.0 OUTLOOK

The Utilities anticipate significant changes in the electrical system serving the province within the five years considered in this plan. The Muskrat Falls hydroelectric development and related interconnection to the North American grid will affect system operations and costs, as well as customer prices. The next iteration of multi-year conservation program planning is anticipated in 2018, to coincide with these events.

In the interim, the approach outlined in the 2016 Plan will remain flexible to address ongoing changes. The initiatives in the 2016 Plan are cost effective based on current information, and were assessed for sensitivity to changes in system costs. As the Utilities implement the program changes outlined in this Plan, they will continue to evaluate program offerings to ensure they create economic benefits and are responsive to evolving customer expectations and market conditions.

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[62] Cost forecasts can be expected to be refined as detailed program design progresses in 2016.

[63] Newfoundland Power has used this approach since 2013, based on Order No. P.U. 13 (2013). Hydro has proposed this approach in its ongoing general rate application, and the proposal has been agreed to by the parties to settlement negotiations in that matter.

[64] While general customer energy conservation costs provide benefits to customers in terms of information, knowhow and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

With growing customer awareness of conservation, and of the takeCHARGE brand, the Utilities will continue to seek opportunities to partner with complementary organizations and trade allies for customers' advantage. Information sharing and policy coordination with the Province will also continue, primarily through the Office of Climate Change and Energy Efficiency.

Table A-1 shows most recent marginal cost forecast as projected by Newfoundland and Labrador Hydro in February 2015.

Table A-1
Marginal Cost Projection
for the
Island Interconnected System
2015 - 2035

	Energy ($/MWh)	Capacity ($/KW – Yr)
2015	108	51
2016	133	70
2017	134	74
2018	47	98
2019	50	99
2020	54	108
2021	56	112
2022	59	115
2023	62	119
2024	65	123
2025	68	126
2026	70	126
2027	73	125
2028	76	125
2029	78	124
2030	81	124
2031	85	121
2032	88	118
2033	92	116
2034	96	113
2035	100	110

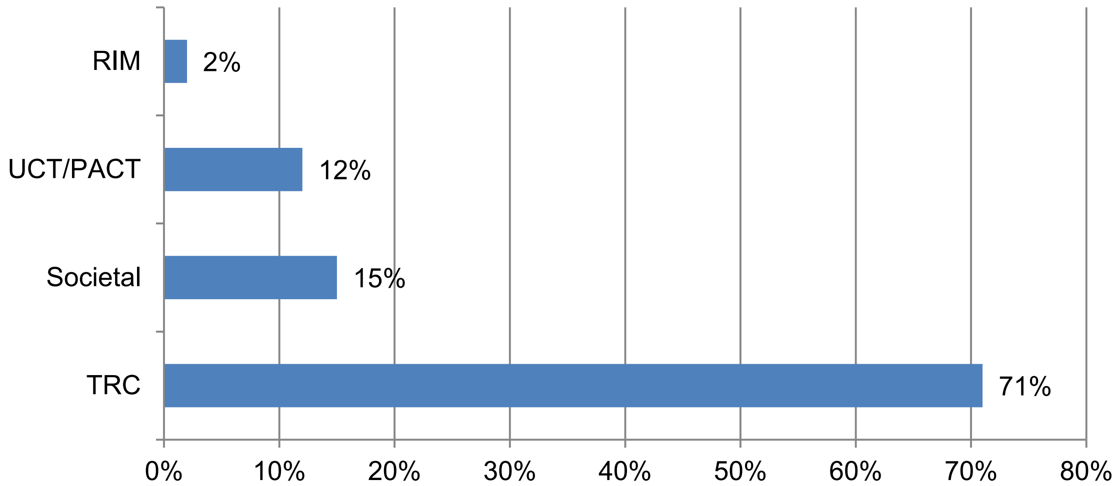
Notes:
1. Modeled as per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs per NLH corporate assumptions, January 2015.
3. Excludes transmission marginal costs.
4. Projection is at customer bulk delivery point.
5. Island Interconnected costs beyond 2017 reflect opportunity cost as per NERA approach.

Table B-1
Current Canadian
Utility Practice
Economic Evaluation Practices

Province	**Economic Test**				
	TRC	PAC	RIM	PCT[1]	SCT[2]
British Columbia	X[3]				
Ontario	X	X			
Nova Scotia	X	X			
Manitoba[4]	X		X	X	X
Saskatchewan	X	X			
Quebec	X		X[5]		
Prince Edward Island	X	X[6]		X	X[6]

1 Participant Cost Test ("PCT").
2 Societal Cost Test ("SCT").
3 British Columbia uses a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.
4 Manitoba also considers the levelized resource cost, net utility benefit, utility net present value, levelized utility cost, and simple customer payback calculation.
5 Quebec considers the RIM as a secondary test.
6 Prince Edward Island considers the PAC and SCT as secondary tests.

Chart B-1
Current American Utility Practice
Economic Evaluation Practices
(Percent of States)



[7]

n=43

[7] Research conducted by the American Council for an Energy Efficient Economy (February 2012) "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs".

Insulation Program

Program Description
The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers completing retrofit projects. Changes to the National Building Code of Canada implemented in December 2012 mandated that all new homes install basement insulation and increased the R-Value requirements in the attic. As a result, this program is only offered to existing homes (i.e. connected to the electricity grid before January 1, 2014) to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be approximately aligned with National Building Code of Canada.
Delivery Strategy
Delivery of this program will continue to be bundled with Thermostat, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio. Marketing initiatives include partnering with retailers and trade allies in the renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through mail and online customer applications.

Insulation Program

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, the practical difficulties of renovating an existing living space and a decreasing number of eligible participants. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities.

Incentive Strategy

Incentives for this program include rebates and financing. In August 2014, the rebate structure was simplified and increased. Customers can now get a rebate of 75% of the cost of materials installed in the basement and 50% of the cost of materials in the attic. Rebates amounts are capped at $1,000.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation and cost effectiveness. A representative sample of installations will be inspected. Formal external evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,187	1,207	1,202	1,197	1,223	6,018
Estimated Cumulative Energy Savings (GWh)	30.0	33.1	36.1	38.9	41.8	180
Total Resource Cost						**2.5**

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats. All thermostats must have a setting precision of +/- 0.5 degrees Celsius or less.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the Insulation, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable & high performance electronic thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through mail and online customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high performance electronic thermostats include lack of awareness of the potential for energy savings, difficulty programming, and reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit is no longer required for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	517	555	539	557	552	2,720
Estimated Cumulative Energy Savings (GWh)	9.7	11.1	12.5	13.8	15.2	62
Total Resource Cost						**2.8**

Small Technologies Program

Program Description

The objective of this program is to increase home energy efficiency and awareness by offering instant rebates on a variety of energy efficient technologies as well as online and mail in rebates for eligible appliances and electronics. This program also includes promotional events to raise awareness of the technologies and to engage the public.

Target Market: Residential

This program is marketed toward all residential customers province wide. All customers are eligible to participate regardless of age of home or heat source. A variety of marketing techniques such as TV news sponsorships, print, radio, online, website, as well as social media channels are used to engage customers.

Eligible Measures

Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions. Instant rebates are available for small energy efficient items such as LEDs and smart power bars, and online and mail in customer applications are required for qualifying models of full-size refrigerators, clothes washers, TVs and full-size Energy Star freezers.

Six new measures will be added to the technology list in 2016. They are:

- Faucet aerators
- Door bottom weather stripping
- Door adhesive
- Window insulation kit
- Electrical outlet gaskets
- Caulking

Small Technologies Program

Delivery Strategy

Partnerships have been made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. Efforts to engage both urban and rural retailers have been made in order to ensure rebated products are available in all areas of the province.

Campaigns are held in the spring and fall each year. During each campaign, the Utilities set up in-store events at the participating locations to raise customer's awareness of the rebates and encourage use of energy efficient products.

Market Considerations

The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.

Incentive Strategy

Incentives for this program include instant rebates for small energy efficient items that will vary by year and campaign. Online and mail in customer applications are available for eligible appliances and electronics. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation.

It is anticipated that this program will end after 2018. The Utilities expect that LEDs will make up the majority of bulbs that are sold in the province. If this occurs, the economics of the program will no longer be cost effective. The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Small Technologies Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	3,113	2,879	1,578	-	-	7,570
Estimated Cumulative Energy Savings (GWh)	23.8	33.3	38.2	37.4	36.5	169
Total Resource Cost						**1.3**

HRV Program

Program Description

The objective of this program is to increase the installation of higher efficiency Heat Recovery Ventilators (“HRV”). The program components include rebates and financing, and a variety of education and marketing tools.

Target Market

This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.

Eligible Measures

Eligible measures in this program include all HRV models that have an SRE of 70% or more and meet the minimum fan efficacy requirements.

Delivery Strategy

Delivery of this program will be bundled with other takeCHARGE residential programs as part of the overall portfolio. Marketing initiatives include partnering with trade allies in the home building and renovation industry, particularly Heating Refrigeration and Air conditioning Institute certified installers. Tools and tactics include website presence, tradeshows, and trade ally activities. Rebates and financing will be processed through customer application.

Market Considerations

The market includes new construction and existing HRV replacement with an emphasis on existing replacements. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these require replacement.

This program has faced a number of barriers such as understanding of what a HRV is and its purpose in the home, initial cost, and awareness of the benefits of selecting more efficient HRVs.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $175 for qualifying HRV units. This reflects the incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. This program has experienced challenging barriers to program participation. Attempting to overcome these barriers can be administratively costly and may outweigh the benefits of program delivery. This program will be monitored to ensure that the participation goals are being met in each year to ensure the program remains cost effective. A representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	223	218	232	231	267	1,171
Estimated Cumulative Energy Savings (GWh)	0.7	1.0	1.3	1.6	2.0	7
Total Resource Cost						**1.3**

Benchmarking Program

Program Description
Energy social benchmarking is the analysis of a household's energy consumption and the comparison of its performance with its energy history and that of other similar households. Historic consumption information, tracking over time and comparisons with other households can encourage customers to reduce energy consumption. A printed paper report is delivered to participating customers via mail. These reports include a normative comparison that compares the customer to similar neighbors. The printed Home Energy Report is supplemented by access to an online web portal allowing for increased customer energy usage information and tips and resources to facilitate energy use reduction.
Target Market: Residential
The Benchmarking program is marketed to residential customers across the province. Customers will be selected into the program and can withdraw (opt-out) at any time.
Eligible Measures
A home's energy use is compared anonymously to the usage patterns of other homes in the vicinity that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide new information to help home owners understand their energy use and find ways to make the home more efficient.
Delivery Strategy
The program is delivered largely by a third party service provider that develops and issues the Home Energy Report and maintains the online web portal. takeCHARGE will oversee all aspects of the program to ensure greater customer insight into their home energy use. The program is available year round and will be supported with takeCHARGE marketing and communication efforts.

Benchmarking Program

Market Considerations

This program will allow the Utilities to reach customers that have not been able to participate in the other incentive programs. It will also allow takeCHARGE actively engage with customers using direct home energy consumption information. This program also allows for the cross promotion of existing takeCHARGE rebate programs as methods to reduce household consumption and to drive participation in these programs.

Incentive Strategy

No monetary incentive will be offered. It has been demonstrated that for this type of program that using social norm comparisons drives the greatest and longest lasting changes to household energy consumption.

Program Monitoring & Evaluation

The program is monitored for participation levels, service quality and cost effectiveness. Formal evaluation will be conducted very two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	530	1,034	989	1,063	-	3,616
Estimated Cumulative Energy Savings (GWh)	0.3	8.0	13.8	15.6	-	38
Total Resource Cost						**1.0**

Mini Split Heat Pump Educational Initiative

Program Description

The objective of the program is to encourage customers to choose high efficiency mini split heat pumps (MSHP), installed by qualified contractors. When installed correctly, a high efficiency MSHP will provide space heating energy savings. The program components include financing, education and marketing initiatives directed towards customers, and direct engagement of certified installers. Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016, however the eligibility criteria for MSHP will be updated to support the uptake of high efficiency units.

Target Market

This program targets residential customers. New home construction and retrofit customers with electric baseboard heat are considered to have the greatest potential for participation, however customer eligibility to participate in financing will not be limited by heating fuel, age or type of dwelling.

Eligible Measures

Financing will now be limited to MSHP with an estimated Heating Seasonal Performance Factor (HSPF) of 9.6 or higher. This is aligned with the minimum HSPF required for certification of units meeting the “ENERGY STAR® Most Efficient 2015” designation. To qualify for financing the installation must be performed by a contractor that has the necessary permits and certification to perform electrical and refrigeration work in the province.

Delivery Strategy

Delivery will be a two pronged approach including marketing to customers and engaging eligible installers.

Marketing initiatives will include information on the takeCHARGE website as well as bill inserts and mass media advertising regarding the benefits of choosing the right heat pump and installer. Installer engagement will include information sessions, contests, and maintaining relationships with qualified installers.

Financing applications will be processed through customer application via the existing customer service channels (online or by phone).

An incentive could not be offered for this program because it does not pass the economic analysis.

Mini Split Heat Pump Educational Initiative

Market Considerations

One of the biggest barriers is a lack of customer awareness and availability of certified installers in rural areas. In order to achieve significant energy savings, the unit must be appropriate for the Newfoundland climate, properly installed and operated.

Other major barriers include identifying what to look for in an installer (i.e. what certification should be required) and difficulty of customers to find qualified installers. The upfront cost of highly efficient units is also a barrier for some customers.

Program Monitoring & Evaluation

This program will be monitored for participation level, and service quality. The criteria for eligible models and installers will also be continually reviewed to ensure the program is promoting units and installers that will provide customers the highest achievable energy savings at a reasonable cost.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	119	100	103	102	104	529

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers who have an interest in making their businesses more energy efficient. The program includes a custom project approach which appeals primarily to large commercial customers. In 2016, the program will also include rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting, which appeal to small and medium sized customers as well.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in electrical energy and demand savings. The program excludes alternative energy and fuel switching.

Beginning in 2016 the custom stream of the Business Efficiency Program will also include incentives for demand reduction based on the options available at the customer's facilities as well as the amount of demand they are able to reduce during peak times.

Also beginning in 2016, the existing fluorescent High Bay program and the current Commercial lighting program (including high performance T8 fluorescent lamps and LED exit signs) will become prescriptive rebates under the Business Efficiency Program.[1] Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts are now considered to be the market standard.

The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems and low flow pre-rinse spray valves will be added to the prescriptive list of incentives.

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1 Prescriptive incentive program are customer energy conservation programs that have per unit rebates for installing certain defined technologies. For example, providing a predefined rebate amount for a LED light bulb;

Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A walk through audit can help customers identify efficiency opportunities.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the program and available incentives, budget & planning cycles, technical know-how, and customer time constraints.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period. Demand saving projects require a minimum of 50 kW savings and be sustainable over 5 years. Incentives of up to $50,000 per site help garner interest and lower customer project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy or demand savings achieved are consistent with incentives paid.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,519	1,791	1,813	2,133	2,171	9,427
Estimated Cumulative Energy Savings (GWh)	18.2	26.9	36.7	47.6	60.2	190
Total Resource Cost						**2.4**

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of the Newfoundland and Labrador industrial market, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally, with external engineering services used as required. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects.

This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

Industrial Energy Efficiency Program

Market Considerations
This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources. The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.
Incentive Strategy
Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.
Program Monitoring & Evaluation
The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[2]						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	667	10	10	10	10	707
Estimated Cumulative Energy Savings (GWh)	30.6	30.6	30.6	30.6	30.6	153
Total Resource Cost						**1.7**

[2] While Customer audits have confirmed that there are several potential projects at Hydro's customers' sites, savings for the Industrial Energy Efficiency Program (IEEP) have only been forecasted for 2016 because there are only five transmission level industrial customers in Newfoundland and Labrador and participation depends on each company's capital budgets and focus for the year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. The costs from 2017-2020 are the fixed administration costs associated with program promotion and customer engagement in the IEEP. The majority of costs are incurred after a project is submitted and passes economic screening. Projects for the Industrial EE Program will be evaluated on a yearly basis and projects with a TRC of 1.0 or greater will be completed.

Isolated Business Efficiency Program

Program Description

The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves will be added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	106	112	117	122	128	585
Estimated Cumulative Energy Savings (GWh)	0.5	0.7	0.8	1.0	1.2	4
Total Resource Cost						**1.6**

Isolated Systems Community Program

Program Description
The objective of this program is to provide a portfolio of technologies and opportunities to help residential and commercial customers in isolated diesel communities save electrical energy and to promote energy efficiency awareness.
Target Market
This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.
Eligible Measures
Measures will range from efficient lighting products, hot water saving products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable. An Appliance Retirement program is being planned for at least one community. Old inefficient appliances will be removed from participating homes and routed for appropriate disposal. This will save energy and money for the homeowner. This component will be evaluated to determine if it is economic to develop into a broader program. The Isolated systems T12 replacement program will take place in 2-3 Isolated communities. This project will offer, free of charge to commercial customers, the supply and install of new High Performance T8 lamps and ballasts.
Delivery Strategy
Hydro has engaged Summerhill Group to deliver this program. They are using a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installs will be completed, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues; this program will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Following the 2015 direct install component, information collected in 2014 and 2015 will be used to plan for Isolated Systems Community programming beyond 2017. Costs and energy savings will be estimated once the technologies have been determined.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. Formal evaluations will be conducted after each year of operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	415	415	-	-	-	830
Estimated Cumulative Energy Savings (GWh)	5.2	5.5	5.5	5.5	5.5	27
Total Resource Cost						**2.7**

Table D-1
Conservation Programs
Energy Reductions: 2012 – 2015(F)
by Sector
(GWh)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	15.8	20.6	24.0	27.0	87.4
Thermostat Program	4.5	5.8	7.0	8.4	25.7
ENERGY STAR Window Program	6.1	8.6	10.1	10.1	34.9
Coupon Program	0.3	0.3	0.3	0.3	1.2
HRV	0.0	0.0	0.2	0.4	0.6
Small Technologies	0.0	0.0	5.5	14.4	19.9
Isolated Systems Community Program	1.7	2.8	4.1	4.8	13.4
Block Heater Timer Program	-	0.3	0.3	0.3	0.9
Total Residential Portfolio	**28.4**	**38.4**	**51.5**	**65.7**	**184.0**
Commercial					
Lighting Rebate Program	3.3	3.9	5.8	6.5	19.5
BEP	-	-	0.6	4.5	5.1
Isolated Systems Business Efficiency Program	-	-	0.1	0.4	0.5
Total Commercial Portfolio	**3.3**	**3.9**	**6.5**	**11.4**	**25.1**
Industrial					
Industrial Energy Efficiency Program	3.3	3.3	25.6	25.6	57.8
Total Portfolio	**35.0**	**45.6**	**83.6**	**102.7**	**266.9**

Table D-2
Conservation Programs
Program Costs: 2012 – 2015(F)
by Sector
($000s)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	882	1,092	796	1,039	3,809
Thermostat Program	492	253	227	454	1,426
ENERGY STAR Window Program	1,173	1,634	698	7	3,512
Coupon Program	-	-	-	-	-
HRV	-	59	56	225	340
Small Technologies	-	4	1,877	2,884	4,765
Isolated Systems Community Program	858	871	615	579	2923
Block Heater Timer Program	31	8	8	-	47
Total Residential Portfolio	**3,436**	**3,921**	**4,277**	**5,188**	**16,822**
Commercial					
Lighting Rebate Program	121	128	373	790	1,412
BEP	-	112	457	532	1,101
Isolated Systems Business Efficiency Program	93	115	96	66	370
Total Commercial Portfolio	**214**	**355**	**926**	**1,388**	**2,883**
Industrial					
Industrial Energy Efficiency Program	173	89	1,244	19	1,525
Total Portfolio	**3,823**	**4,365**	**6,447**	**6,595**	**21,230**

Table E-1
Conservation Programs
Energy Reduction Estimates: 2016 – 2020
by Sector
(GWh)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	30.0	33.1	36.1	38.9	41.8	179.9
Thermostat Program	9.7	11.1	12.5	13.8	15.2	62.3
ENERGY STAR Window Program	10.1	10.1	10.1	10.1	10.1	50.5
Coupon Program	0.3	0.3	0.3	0.3	0.3	1.5
Isolated Systems Community Program	5.2	5.5	5.5	5.5	5.5	27.2
Small Technology Program	23.8	33.3	38.2	37.4	36.5	169.1
HRV Program	0.7	1.0	1.3	1.6	2.0	6.6
Benchmarking	0.3	8.0	13.8	15.6	-	37.7
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**80.4**	**102.7**	**118.1**	**123.5**	**111.7**	**536.4**
Commercial						
Isolated Systems Business Efficiency Program	0.5	0.7	0.8	1.0	1.2	4.3
Business Efficiency Program	18.2	26.9	36.7	47.6	60.2	189.6
Total Commercial Portfolio	**18.7**	**27.6**	**37.5**	**48.6**	**61.4**	**193.8**
Industrial						
Industrial Energy Efficiency Program	30.6	30.6	30.6	30.6	30.6	153.0
Total Portfolio	**129.7**	**160.9**	**186.2**	**202.7**	**203.7**	**883.2**

Table E-2
Conservation Programs
Program Cost Estimates: 2016 – 2020
by Sector
($000s)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	1,189	1,207	1,202	1,197	1,223	6,018
Thermostat Program	517	555	539	557	552	2,720
Isolated Systems Community Program	415	415	-	-	-	830
Small Technology Program	3,113	2,879	1,578	-	-	7,570
HRV Program	223	218	232	231	267	1,171
Benchmarking Program	530	1,034	989	1,063	-	3,616
Total Residential Portfolio	**5,987**	**6,308**	**4,540**	**3,048**	**2,042**	**21,925**
Commercial						
Isolated Systems Business Efficiency Program	106	112	117	122	128	585
Business Efficiency Program	1,522	1,794	1,816	2,136	2,173	9,441
Total Commercial Portfolio	**1,628**	**1,906**	**1,933**	**2,258**	**2,301**	**10,026**
Industrial						
Industrial Energy Efficiency Program	667	10	10	10	10	707
Total Programs Portfolio	**8,282**	**8,224**	**6,483**	**5,316**	**4,353**	**32,658**

Table E-3
Conservation Programs
Total Resource Cost Test Results
by Sector

	TRC Results
Residential	
Insulation Program	2.5
Thermostat Program	2.8
Isolated Systems Community Program	2.7
Small Technology Program	1.3
HRV Program	1.3
Benchmarking	1.0
Commercial	
Isolated Systems Business Efficiency Program	1.6
Business Efficiency Program	2.4
Industrial	
Industrial Energy Efficiency Program	1.7

Labour Forecast
2015-2017

October 2015

Table of Contents

1.0. BACKGROUND

This report contains detailed information concerning the method used by Newfoundland Power to forecast its test year full-time equivalents ("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] In managing its workforce, the Company matches overall capacity and capability with anticipated work requirements.

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.

Workforce Options

Having determined the annual work requirements, the Company considers the amount of internal labour available 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

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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 2014 through 2017F, Newfoundland Power's workforce is forecast to decrease by 1.9% or 12.6 FTEs.

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.

a highly skilled core workforce and 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 an 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 recently completed year include only the actual paid hours *worked in that year*. For this reason, the FTEs for the most recently completed year are the basis Newfoundland Power uses for forecasting FTEs.

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],

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

8 Approximately 7% 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 58% 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.

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.

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 2015 are approximately $75.0 million. For the 2016 and 2017 test year, the total forecast labour requirements are $76.5 million and $77.0 million respectively. These requirements reflect forecast capital and operational work requirements for each year.

The Company's forecast internal labour expense for 2015 is $63.7 million. For 2016 and 2017, forecast internal labour expense is $66.3 million and $67.4 million respectively. The difference between the total forecast labour requirement and the Company's internal labour available will be addressed using contract labour.

3.0 2015 to 2017 LABOUR FORECASTS

2015 FTEs and Internal Labour Expense

The 2015 FTEs and internal labour expense were calculated using the 2014 year-end FTEs and labour expense as the starting point. In 2014, the year-end FTEs, based on the *actual hours worked,* was 664.8. The associated internal labour expense was $62.5 million.

To account for the impact of inflation in developing the 2015 forecast, the 2014 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 2015 forecast reflects 37 projected retirements, with 19 of these employees to be replaced, plus 9 regular new hires. The new hires

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, 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, 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.

will meet Newfoundland Power's management of the ongoing demographic transition in its workforce. In addition, the 2015 FTEs and internal labour expense are increased to reflect new employees who worked a partial year in 2014, but are anticipated to be in the workforce for a full year in 2015, offset by employees who left in 2014.

Schedule A presents the detailed breakdown of forecast internal labour expense and FTEs for 2015.

2016 FTEs and Internal Labour Expense

The 2016 FTEs and internal labour expense were calculated using the 2015 forecast as the starting point. To account for the impact of inflation, the 2015 internal labour expense is adjusted to reflect salary increases applicable to 2016.

The test year labour forecast reflects 39 projected retirements, with 30 of these employees to be replaced, plus 13 new hires. The new hires will meet increased requirements for Powerline Technician Apprentices and additional resources for expansion of customer energy conservation programming. In addition, the 2016 FTEs and internal labour expense includes employees working a partial year in 2015 who are anticipated to be in the workforce for a full year in 2016, offset by employees who left in 2015.

Schedule B presents the detailed breakdown of forecast internal labour expense and FTEs for 2016.

2017 FTEs and Internal Labour Expense

The 2017 FTEs and internal labour expense were calculated using the 2016 forecast as the starting point. To account for the impact of inflation, the 2016 internal labour expense is adjusted to reflect salary increases applicable to 2017.

The test year labour forecast reflects an overall reduction of 13.0 FTEs primarily due to completion of the AMR project.

Schedule C presents the detailed breakdown of forecast internal labour expense and FTEs for 2017.

Schedule A
2015 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2014 Workforce			
Operating	32,114		1
Capital	26,021		
Rechargeable & Recoverable	4,374		
Total	**62,509**	**664.8**	2
2015 Salary Increase	2,188		3
Adjustments for 2015			
2015 Retirements			
Employee Retirement[15]	(2,339)	(20.7)	4
Retirement Replacement	1,037	10.2	5
2015 Leaves of Absence			
Employees Taking Leaves	(569)	(6.1)	6
Employees Returning from Leaves	105	1.1	7
Terminations[16]	(274)	(2.6)	8
New Hires	683	7.3	9
Partial Year Adjustments[17]	361	7.1	10
Loading Impact shift to capital/R&R			
2015 Adjusted Workforce	**63,701**	**661.1**	11
2015 Forecast Workforce			
Operating	31,455		12
Capital	27,294		
Rechargeable & Recoverable	4,952		
Total	**63,701**		13

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

[16] Terminations include both voluntary and non-voluntary termination of employment with the Company.

[17] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2015. These employees would not have accounted for full annual salaries in the 2014 labour expense, nor would they have accounted for full FTEs in 2014. These adjustments also include employees who left the Company in 2014. These employees do not account for full annual salaries in the 2015 labour expense, nor would they account for full FTEs in 2015.

Notes for Schedule A

No.	Description
1	The actual year end operating labour cost for 2014. It includes the impact of all retirements, leaves of absence, terminations and new hires experienced in 2014.
2	The 2014 actual year end FTEs count is reflective of the 2014 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 2014. Total labour expense includes overhead loading for vehicle expenses.
3	The 2015 salary increase is based upon a weighted average salary increase of 3.5%.
4	In 2015, there are 37 employees who are expected to retire. The 2015 labour reduction for retirement is \$2,339,033. Due to the timing of the estimated retirements, the 2015 reduction in FTEs is 20.7.
5	19 of the retiring employees will be replaced in 2015. A combination of lower salary and the timing of replacement hires, results in \$1,037,021 labour cost and 10.2 FTE increase for 2015.
6	In 2015, the Company forecasts 9 leaves of absence, consisting of 4 maternity leaves and 5 long-term disability absences. The 2015 labour reduction for leaves is \$568,985 with a corresponding FTE reduction of 6.1.
7	In 2015, the Company forecasts 4 employees returning from various forms of leave. This includes 1 employee on maternity leave and 3 on long-term disability. The 2015 labour increase for leaves is \$105, 027 with a corresponding FTE increase of 1.1.
8	In 2015, the Company forecasts 5 employees terminating their employment. This includes 1 deceased employee. The 2015 labour reduction for terminations is \$273,703 with a corresponding FTE reduction of 2.6.
9	In 2015, the Company forecasts 9 regular new hires. These new hires do not include replacement employees associated with retirements The 2015 labour increase for new hires is \$683,462, with a corresponding FTE increase of 7.3.
10	The 2015 labour increase for partial year adjustments is \$361,446, with a corresponding FTE increase of 7.1.
11	The 2015 forecast FTE count.
12	The 2015 forecast operating labour cost, excluding overtime.
13	Total labour expense includes overhead loading for vehicle expenses.

Schedule B
2016 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2015 Forecast Workforce			
Operating	31,455		1
Capital	27,294		
Rechargeable & Recoverable	4,952		
Total	**63,701**	**661.1**	2
2016 Salary Increase	**2,070**		3
Extra Day in 2016	244		4
Adjustments for 2016			
2016 Retirements			
Employee Retirement[18]	(1,791)	(14.5)	5
Retirement Replacement	1,828	15.3	6
2016 Leaves of Absence			
Employees Taking Leaves	(377)	(3.4)	7
Employees Returning from Leaves	595	6.0	8
Terminations[19]	(441)	(5.1)	9
New Hires	678	8.0	10
Partial Year Adjustments[20]	(221)	(2.2)	11
2016 Adjusted Workforce	**66,286**	**665.2**	12
2016 Forecast Workforce			
Operating	32,298		13
Capital	28,914		
Rechargeable & Recoverable	5,074		
Total	**66,286**		14

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

[19] Terminations include both voluntary and non-voluntary termination of employment with the Company.

[20] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2016. These employees would not have accounted for full annual salaries in the 2015 labour expense, nor would they have accounted for full FTEs in 2015. These adjustments also include employees who left the Company in 2015. These employees do not account for full annual salaries in the 2016 labour expense, nor would they account for full FTEs in 2016.

Notes for Schedule B

No.	Description
1	The forecast operating labour cost for 2015. It includes the impact of all retirements, leaves of absence, terminations and new hires anticipated for 2015, and reflected in the adjustments set out in Schedule A.
2	The 2015 forecast FTEs are reflective of the forecast 2015 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 2015, and reflected in Schedule A. Total labour expense includes overhead loading for vehicle expenses.
3	The 2016 salary increase is based upon a weighted average salary increase of 3.25%.
4	In 2016, there are 262 working days versus 261 working days in 2015, resulting in a labour increase of $244,000.
5	In 2016, there are 39 employees expected to retire. The 2016 labour reduction for retirement is $1,790,935. The 2016 reduction in FTEs of 14.5 reflects the timing of the forecast retirements.
6	30 of the retiring employees will be replaced in 2016 which results in $1,828,324 labour cost and an 15.3 FTE increase for 2016.
7	In 2016, the Company forecasts 8 employees taking leaves of absence based upon recent experience. The 2016 labour reduction for leaves is $376,629 with a corresponding FTE reduction of 3.4.
8	In 2016, the Company forecasts 9 employees returning from various forms of leave. These include 5 employees on maternity leave and 4 employees on long-term disability. The 2016 labour increase for leaves is $594,946, with a corresponding FTE increase of 6.0.
9	In 2016, the Company forecasts 4 employees terminating their employment based upon recent experience as well as the 2016 impact of Automatic Meter Reading (AMR) strategy. The 2016 labour reduction for terminations is $440,553, and a corresponding FTE reduction of 5.1.
10	In 2016, the Company forecasts 3 new hires related to customer energy conservation , 9 PLT Apprentices and 1 program analyst. These new hires do not include replacement employees associated with retirements. The 2016 labour increase for new hires is $677,565, with a corresponding FTE increase of 8.0.
11	The 2016 labour increase for partial year adjustments is a decrease of $221,000 with a corresponding FTE decrease of 2.2.
12	The 2016 forecast FTE count.
13	The 2016 forecast operating labour cost excluding overtime.
14	Total labour expense includes overhead loading for vehicle expenses.

Schedule C
2017 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2016 Forecast Workforce			
Operating	32,298		1
Capital	28,914		
Rechargeable & Recoverable	5,074		
Total	**66,286**	**665.2**	2
2017 Salary Increase	**2,154**		3
Adjustments for 2017			
2017 Retirements			
Employee Retirement[21]	(1,004)	(9.2)	4
Retirement Replacement	872	7.6	5
2017 Leaves of Absence			
Employees Taking Leaves	(412)	(3.7)	6
Employees Returning from Leaves	302	2.8	7
Terminations[22]	(429)	(4.7)	8
New Hires	240	3.0	9
Partial Year Adjustments[23]	(564)	(8.8)	10
2017 Adjusted Workforce	**67,445**	**652.2**	11
2017 Forecast Workforce			
Operating	32,841		12
Capital	29,403		
Rechargeable & Recoverable	5,201		
Total	**67,445**		13

[21] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.
[22] Terminations include both voluntary and non-voluntary termination of employment with the Company.
[23] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2017. These employees would not have accounted for full annual salaries in the 2016 labour expense, nor would they have accounted for full FTEs in 2016.

Notes for Schedule C

No.	Description
1	The forecast operating labour cost for 2016. It includes the impact of all retirements, leaves of absence, terminations and new hires anticipated for 2016, and reflected in the adjustments set out in Schedule B.
2	The 2016 forecast FTEs are reflective of the forecast 2016 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 2016, and reflected in Schedule B. Total labour expense includes overhead loading for vehicle expenses.
3	The 2017 salary increase is based upon a weighted average salary increase of 3.25%.
4	In 2017, there are 23 employees expected to retire. The 2017 labour reduction for retirement is $1,004,377. The 2017 reduction in FTEs of 9.2 reflects the timing of the forecast retirements.
5	19 of the retiring employees will be replaced in 2017. A combination of lower salary and the timing of replacement hires, results in $872,366 labour cost and a 7.6 FTE increase.
6	In 2017, the Company forecasts 8 employees taking leaves of absence based upon recent experience. The 2017 labour reduction for leaves is $411,760 with a corresponding FTE reduction of 3.7.
7	In 2017, the Company forecasts 5 employees returning from various forms of leave. The 2017 labour increase for leaves is $302,267, with a corresponding FTE increase of 2.8.
8	In 2017, the Company forecasts 4 employees terminating their employment based upon recent experience as well as the 2017 impact of AMR strategy. The 2017 labour reduction for terminations is $429,035, and a corresponding FTE reduction of 4.7.
9	In 2017, the Company forecasts 6 PLT Apprentices hires. These new hires do not include replacement employees associated with retirements. The 2017 labour increase for new hires is $240,443, with a corresponding FTE increase of 3.0.
10	The 2017 labour increase for partial year adjustments is a decrease of $564,000, with a corresponding FTE decrease of 8.8.
11	The 2017 forecast FTE count.
12	The 2017 forecast operating labour cost excluding overtime.
13	Total labour expense includes overhead loading for vehicle expenses.

2016 and 2017 Rate Base Allowances

October 2015

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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.

The CWC Allowance calculated for 2016 and 2017 is $8,484,000 and $8,270,000 respectively. This is approximately 1.3% of forecast 2016 and 2017 regulated cash operating expenses.[2]

The Materials Allowance calculated for 2016 and 2017 is $6,675,000 and $6,814,000 respectively. This reflects a revised expansion factor for the calculation of expansion inventory of 20.61%.[3]

2.0 CWC ALLOWANCE

2.1 Methodology

The inclusion of a CWC Allowance in rate base, and the use of a lead/lag study to calculate the allowance are accepted practices for regulated utilities. A lead/lag study recognizes that the utility provides service to customers prior to the receipt of payment for that service. 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 Newfoundland and Labrador Hydro's rate base includes these 3 allowances in addition to a fuel inventory allowance.

2 This compares to $6,605,000 and $6,384,000 or 1.7% of forecast regulated cash operating expenses, used in 2013 and 2014. Although the percentage has dropped since 2013 and 2014, the change in HST Adjustment has led to an increase in the CWC Allowance for 2016 and 2017. See Section 2.2 for further detail.

3 This compares with a materials allowance of $5,140,000 and $5,247,000 which included an expansion factor of 22.53% used in 2013 and 2014.

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.[4]
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 Leads & Lags : 2016 & 2017

General

In determining its 2016 and 2017 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 2014 actual data as it represents the most recent historical results available at the time.

Compared to 2013, there have been two notable changes to the calculation of Newfoundland Power's cash working capital allowance. These changes are related to corporate income taxes and HST rebates. The timing and amount of payments for the Company's 2014 corporate income taxes has increased the expense lag over the 2013 lead/lag study. Effective July 1, 2015, the Government of Newfoundland and Labrador ended a residential energy rebate equivalent to the provincial portion (8 percent) of the 13 percent HST.

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 2016 and 2017 test years. Together, these leads and lags form the basis for the 2016/2017 CWC Allowance.

The leads and lags calculated have been applied to the Company's forecast 2016 and 2017 test year data to calculate the proposed CWC Allowance. These calculations are summarized on the following page.

[4] 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.

Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2014 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. 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 of pole rentals, work done by the Company for others, and various miscellaneous revenues and HST.

Revenue lags were calculated for consumer billings and other billings. These were weighted, based on the percentage of the total 2016 and 2017 forecast billings represented by each, to produce a total weighted average revenue lag of 37.76 days for 2016 and 37.73 days for 2017.[5] These are set out in Schedule 1 of Appendices A and B.

Expense Lag

The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2014 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 2016 and 2017 forecast cash operating expenses represented by each to produce a total weighted average expense lag for the Company of 32.85 days for 2016 and 32.89 days for 2017.[6] These are set out in Schedule 2 of Appendices A and B.

For 2016 and 2017, the expense lag associated with the payment of corporate income taxes has changed in comparison to the lag included in the 2014 test year cash working capital study. In determining the expense lag for corporate income taxes, the actual 2014 tax payments were analyzed and weighted against the average service lag. It is normal practice that a final tax payment is made to settle the tax account once the corporate tax return is finalized. For the 2014 tax year, a final tax payment was made on March 2, 2015 of approximately $6,700,000.[7]

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[5] By comparison, the revenue lag included in the 2013 and 2014 test year cash working capital study was 36.92 days for 2013 and 36.74 days for 2014.

[6] By comparison, the expense lag included in the 2013 and 2014 test year cash working capital study was 30.61 days for 2013 and 30.57 days for 2014.

[7] By comparison, the final tax payment included in the analysis for the 2013 and 2014 test year cash working capital study was approximately $1.9 million.

This effectively increased the expense lag for corporate income taxes in 2014 and contributed to an increase in the 2016 and 2017 forecast expense lag over the 2013/2014 test years.[8]

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.

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.

In 2011, the Government of Newfoundland and Labrador implemented a residential energy rebate equivalent to the provincial portion (8 percent) of the 13 percent HST. Effective July 1, 2015, this rebate ended. Prior to this development, Newfoundland Power received a HST rebate from the Government of Newfoundland and Labrador approximately 40 days before the HST was required to be paid. As a result of the end of the rebate program, the weighted average lead with respect to HST on consumer billings has decreased from 34.6 days in 2013 and 2014 to approximately 24.3 days in both 2016 and 2017.[9]

The net HST impact is an increase in the Company's proposed 2016 and 2017 test year CWC Allowance of $1,084,000 in 2016 and $931,000 in 2017. The 2013 test year HST adjustment of ($1,986,000) and 2014 HST adjustment of ($2,180,000) decreased the 2013 and 2014 CWC allowance. The change in HST adjustments primarily reflects the conclusion of the provincial residential energy HST rebate in 2015.[10] Newfoundland Power's 2016 and 2017 HST adjustments are set out in Schedule 3 of Appendices A and B.

2.3 Test Year CWC Allowance: 2016 & 2017

Newfoundland Power's proposed 2016 and 2017 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $8,483,000 in 2016 and $8,270,000 in 2017. These are set out in Schedule 4 of Appendices A and B.[11]

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8 The 2013/2014 test year weighted average expense lags related to corporate income taxes was 1.50 and 1.51. The weighted average expense lag for corporate income taxes is 2.97 in 2016 and 3.16 in 2017. The increase in the expense lag means that Newfoundland Power has use of these funds for a longer period of time thereby reducing the financing requirements for corporate income taxes.

9 The decrease in the lead time for the payment of HST reflects the fact that the Company will no longer receive a rebate from the Government of Newfoundland and Labrador in advance of the required HST payment.

10 The increase in HST from 13% to 15% effective January 1, 2016 has been incorporated into the 2016 and 2017 test year calculations.

11 By comparison, the cash working capital allowance included in the 2013 test year was $6.6 million, and $6.4 million in the 2014 test year.

The effect of the proposed 2016 and 2017 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.[12]

In Order No. P.U. 13 (2013), 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 22.53%.[13]

For the 2016/2017 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 2014 used for expansion projects. The revised expansion factor for the 2016 and 2017 test year is 20.61% versus 22.53% calculated for the 2014 test year.

[12] 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 related to expansion are excluded in the calculation of rate base.

[13] Newfoundland Power's average rate base for the 2014 test year was approved by the Board in Order No. P.U. 23 (2013) and included the Company's revised calculation of its materials and supplies allowance.

Newfoundland Power Inc.

2016 Forecast Revenue Lag

	Cash Inflows	2016 Forecast [1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	679,805	99.49%	36.56	36.37
2	Other Billings	3,455	0.51%	271.00	1.38
3	Total	683,260	100.00%		**37.76**
4					
5					
6					
7					
8					
9					
10					

11	[1] Reconciliation to 2016 Revenue Requirement ($000s) :	
12	Total Billings Above	683,260
13	Rate Stabilization Adjustments	6,275
14	Municipal Tax Billings	(16,405)
15	Billings Recorded as Revenue	673,130
16	Revenue excluded from CWC Allowance	
17	Revenue Accrual (non-cash)	1,362
18	Equity Portion of AFUDC	482
19	Total Revenue	674,974
20	Deduct: Other Revenue	(5,289)
21	2016 Revenue Requirement from Rates	669,685

Newfoundland Power Inc.

2016 Forecast Expense Lag

		2016 Forcast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	37,157		37,157	6.75%	37.15	2.51
2	Vehicle Expenses	1,721		1,721	0.31%	45.21	0.14
3	Operating Materials	1,662		1,662	0.30%	45.21	0.14
4	Inter-Company Charges	2,197		2,197	0.40%	45.21	0.18
5	Plants,Subs,System Ops & Buildings	2,298		2,298	0.42%	45.21	0.19
6	Travel	1,255		1,255	0.23%	45.21	0.10
7	Tools and Clothing Allowance	1,147		1,147	0.21%	45.21	0.09
8	Conservation Costs	2,792		2,792	0.51%	45.21	0.23
9	Miscellaneous	1,995		1,995	0.36%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,164		1,164	0.21%	(16.18)	(0.03)
11	Uncollectible Bills	1,327	1,327	0	0.00%		-
12	Insurance	1,258		1,258	0.23%	(167.50)	(0.38)
13	Pension & ERP Expense	13,407	9,929	3,478	0.63%	30.40	0.19
14	Other Post Employment Benefits	8,769	5,798	2,971	0.54%	34.80	0.19
15	Severence and Other Employee Costs	74		74	0.01%	45.21	0.01
16	Education and Training	359		359	0.07%	45.21	0.03
17	Trustee & Directors' Fees	473		473	0.09%	36.24	0.03
18	Other Company Fees[2]	3,307		3,307	0.60%	45.21	0.27
19	Stationery & Copying	283		283	0.05%	45.21	0.02
20	Equipment Rental & Maintenance	813		813	0.15%	45.21	0.07
21	Telecommunications	1,608		1,608	0.29%	45.21	0.13
22	Postage	1,553		1,553	0.28%	45.21	0.13
23	Advertising	1,728		1,728	0.31%	45.21	0.14
24	Vegetation Management	1,850		1,850	0.34%	45.21	0.15
25	Computer Equipment & Software	1,266		1,266	0.23%	45.21	0.10
26	Gross operating expenses	91,463		74,409			
27	Less: GEC	(3,525)		(3,525)	-0.64%	36.33	(0.23)
28	Net Operating Expenses	87,938		70,884			
29	Less: Non-Regulated Expenses	(2,990)		(2,990)	-0.54%	41.74	(0.23)
30	**Regulated Operating Expenses**	84,948		67,894			
31							
32	**Purchased Power**	448,197		448,197	81.40%	35.63	29.00
33							
34	**Current Income Tax**						
35	Total Tax	17,719	491	17,228			
36	Plus: Tax Effects of Non-Regulated Expenses	867		867			
37	Regulated Current Income Tax	18,586		18,095	3.29%	90.30	2.97
38							
39	**Municipal Tax Paid**			16,405	2.98%	(115.96)	(3.46)
40							
41	**Cash Operating Expenses in CWC Allowance**			550,591	100.00%		**32.85**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	81,214					
45	Depreciation Expense	55,535					
46	Deferred cost recoveries and amortizations[3]	(7,526)					
47		129,223					
48							
49	**2016 Revenue Requirement**	680,954					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes the amortization of 2013 Hearing costs ($400,000), the deferred recovery of conservation costs (-$6,544,000), the amortization of conservation costs ($1,894,000) and the amortization and deferred recovery of 2013/2016 revenue shortfalls (-$3,276,000). See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2016 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(100,988)	(24.28)	(6,718)
2	Other Billings	(572)	225.37	353
3	Purchased Power	67,230	40.42	7,445
4	Operating Expenses	3,755	0.42	4
5				**1,084**
6				

7 [1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2016 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	37.76
2	Expense Lag Days (Schedule 2)	(32.85)
3	Net Lag Days	4.91
4		
5	CWC Factor (4.91 days divided by 365 days)	1.344%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	550,591
13	CWC Factor	1.344%
14		7,400
15	HST Adjustment (Schedule 3)	1,084
16	**CWC Allowance**	**8,484**

Newfoundland Power Inc.

2017 Forecast Revenue Lag

Cash Inflows	2017 Forecast [1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
Consumer Billings	693,963	99.50%	36.56	36.38
Other Billings	3,473	0.50%	271.00	1.36
Total	697,436	100.00%		**37.73**

[1] Reconciliation to 2017 Revenue Requirement ($000s) :

Total Billings Above	697,436
Rate Stabilization Adjustments	6,277
Municipal Tax Billings	(16,735)
Billings Recorded as Revenue	686,978
Revenue excluded from CWC Allowance	
Revenue Accrual (non-cash)	432
Equity Portion of AFUDC	490
Total Revenue	687,900
Deduct: Other Revenue	(5,322)
2017 Revenue Requirement from Rates	682,578

Newfoundland Power Inc.

2017 Forecast Expense Lag

		2017 Forcast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	37,956		37,956	6.85%	37.15	2.55
2	Vehicle Expenses	1,611		1,611	0.29%	45.21	0.13
3	Operating Materials	1,697		1,697	0.31%	45.21	0.14
4	Inter-Company Charges	2,295		2,295	0.41%	45.21	0.19
5	Plants,Subs,System Ops & Buildings	2,346		2,346	0.42%	45.21	0.19
6	Travel	1,275		1,275	0.23%	45.21	0.10
7	Tools and Clothing Allowance	1,171		1,171	0.21%	45.21	0.10
8	Conservation Costs	2,895		2,895	0.52%	45.21	0.24
9	Miscellaneous	2,011		2,011	0.36%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,189		1,189	0.21%	(16.18)	(0.03)
11	Uncollectible Bills	1,355	1,355	0	0.00%		-
12	Insurance	1,284		1,284	0.23%	(167.50)	(0.39)
13	Pension & ERP Expense	9,606	6,018	3,588	0.65%	30.40	0.20
14	Other Post Employment Benefits	8,289	4,912	3,377	0.61%	34.80	0.21
15	Severence and Other Employee Costs	75		75	0.01%	45.21	0.01
16	Education and Training	367		367	0.07%	45.21	0.03
17	Trustee & Directors' Fees	483		483	0.09%	36.24	0.03
18	Other Company Fees[2]	3,265		3,265	0.59%	45.21	0.27
19	Stationery & Copying	289		289	0.05%	45.21	0.02
20	Equipment Rental & Maintenance	831		831	0.15%	45.21	0.07
21	Telecommunications	1,641		1,641	0.30%	45.21	0.13
22	Postage	1,586		1,586	0.29%	45.21	0.13
23	Advertising	1,721		1,721	0.31%	45.21	0.14
24	Vegetation Management	1,889		1,889	0.34%	45.21	0.15
25	Computer Equipment & Software	1,328		1,328	0.24%	45.21	0.11
26	Gross operating expenses	88,455		76,170			
27	Less: GEC	(3,162)		(3,162)	-0.57%	36.33	(0.21)
28	Net Operating Expenses	85,293		73,008			
29	Less: Non-Regulated Expenses	(3,225)		(3,225)	-0.58%	41.74	(0.24)
30	**Regulated Operating Expenses**	82,068	59,092	69,783			
31							
32	**Purchased Power**	447,927		447,927	80.88%	35.63	28.82
33							
34	**Current Income Tax**						
35	Total Tax	18,662	229	18,433			
36	Plus: Tax Effects of Non-Regulated Expenses	935		935			
37	Regulated Current Income Tax	19,597		19,368	3.50%	90.30	3.16
38							
39	**Municipal Tax Paid**			16,735	3.02%	(115.96)	(3.50)
40							
41	**Cash Operating Expenses in CWC Allowance**			553,813	100.00%		**32.89**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	84,416					
45	Depreciation Expense	58,573					
46	Deferred cost recoveries and amortizations[3]	(2,367)					
47		140,622					
48							
49	**2017 Revenue Requirement**	690,214					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes the amortization of 2013 Hearing costs ($400,000), the deferred recovery of conservation costs (-$7,231,000), the amortization of conservation costs ($2,828,000) and the amortization of 2013/2016 revenue shortfalls ($1,636,000).
See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2017 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(103,247)	(24.28)	(6,868)
2	Other Billings	(575)	225.37	355
3	Purchased Power	67,189	40.42	7,440
4	Operating Expenses	3,794	0.42	4
5				**931**
6				

7 [1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2017 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	37.73
2	Expense Lag Days (Schedule 2)	(32.89)
3	Net Lag Days	4.84
4		
5	CWC Factor (4.84 days divided by 365 days)	1.325%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	553,813
13	CWC Factor	1.325%
14		7,339
15	HST Adjustment (Schedule 3)	931
16	**CWC Allowance**	**8,270**

Customer, Energy and Demand Forecast

October 2015

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 INTRODUCTION

The Customer, Energy and Demand forecast (the "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 addresses the estimation of future revenue from electrical sales and the Company's single largest expenditure, purchased power.

The forecast was created as of August, 2015.

2.0 FORECAST METHODOLOGY

Introduction
Newfoundland Power provides electrical service to three distinct categories of customers including domestic, general service and street and area lighting. In 2014, domestic accounted for 61% of total energy sales while general service and street and area lighting represented 38% and 1%, respectively.

Domestic
The domestic category includes Rate # 1.1 Domestic Service and Rate # 1.1S Domestic Seasonal – Optional. The domestic category 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 growth in the number of customers is primarily based on forecast housing starts. 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.

General Service
The general service category primarily refers to commercial, institutional and industrial customers. Unlike the domestic category which represents a relatively homogenous group of customers, the general service category represents a relatively 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 2014, 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 General Service 0 – 100 kW (110 kVA) and large general service which includes Rate # 2.3 General Service 110 kVA (100 kW) – 1000 kVA and Rate # 2.4 General Service 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. Average use is forecast using an econometric model that includes the

Gross Domestic Product (”GDP”) for the service sector per small general service customer 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
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 2014, approximately 62,000 high pressure sodium fixtures were installed. 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.

Produced and Purchased
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.[1]

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.

Peak Demand
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. Purchased power demand is calculated by subtracting load curtailment by Newfoundland Power customers and at company owned facilities, and 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.

[1] Wheeled energy represents energy that is supplied to Newfoundland and Labrador Hydro customers through Newfoundland Power’s electrical system.

3.1 Economic Outlook

The economic assumptions used in preparing the customer, energy and demand forecasts are based on the Conference Board of Canada, *Provincial Outlook Summer 2015, Economic Forecast*, dated July 16, 2015. A table summarizing the historical and forecast key economic indicators for 2009 to 2017 is provided in Appendix A. A copy of the Conference Board of Canada's economic forecast is Attachment A.

Over the past 5 years Newfoundland and Labrador has experienced robust economic growth. This performance has been largely attributed to large resource based projects including:

- expansions to existing offshore oilfields;
- the construction of the gravity based structure for the Hebron offshore oilfield;
- the construction and production from Vale's hydromet facility at Long Harbour;
- the development of a number of other mining projects in Labrador; and
- the construction of the Muskrat Falls Hydroelectric Project and associated transmission links.

High oil and metal prices played a pivotal role in the development of most of these projects and positively impacted the Province's fiscal position and infrastructure spending during this period. This strong performance is reflected in the various key economic indicators such as: Gross Domestic Product, in particular the service sector; household disposable income; unemployment rates; and housing starts.

Over the forecast period the economy of Newfoundland and Labrador is expected to struggle. The decline in oil production from existing oilfields; the winding down of construction of Vale's hydromet facility at Long Harbour and the gravity based structure for the Hebron offshore oilfield, and a significant drop in the price of oil and other metals such as iron ore will all negatively impact economic performance. These developments will also significantly impact the fiscal position of the Province and infrastructure spending.

On the positive side industries involved in the export of goods and services such as seafood and newsprint will benefit from a lower Canadian dollar. The manufacturing sector will also receive a boost from increased nickel processing at Vale's hydromet facility at Long Harbour over the next few years.

Overall, growth in key economic indicators such as service sector Gross Domestic Product, employment levels, household disposable income and housing starts will be significantly lower during the forecast as compared to recent history. Given Newfoundland Power's customer base, energy sales growth is primarily influenced by the domestic economy and these key economic indicators. Therefore, forecast customer and energy sales growth is lower than experienced in recent years.

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, customer response to changes in the price of electricity is relatively inelastic. A 1% change in the price of electricity will result in a change in energy sales of less than 1%. Current analysis indicates that a 1% increase in the price of electricity will result in a 0.20% decrease in energy sales. It 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.

Electricity price forecasts are developed based on information available internally and provided by Newfoundland and Labrador Hydro. The energy sales forecast under existing rates includes: a 2.0% increase on July 1, 2014 related to the annual review of the Rate Stabilization Account; 5.25% decrease on July 1, 2015 related to the annual review of the Rate Stabilization Account and Newfoundland Hydro Interim Rate increase; the elimination of the 8% Residential Rebate on July 1, 2015, and the increase in HST from 13% to 15% effective January 1, 2016. Newfoundland Power's proposed 3.1% increase in customer rates effective July 1, 2016 has also been included in the energy sales forecast under proposed rates.

Furnace oil prices are forecast to decline by 22% in 2015 and increase by 10% as world oil prices start to rebound.[2] Furnace oil prices are assumed to increase at the rate of inflation in 2017.

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 Conservation Plan: 2016 – 2020.*[3]

3.4 Other Inputs

Information from a number of other sources is also used in preparing the forecast. Each year Newfoundland Power surveys approximately 175 large general service customers representing approximately 450 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.

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[2] Based on US Energy Information Administration, Short-Term Energy Outlook – July 2015 adjusted to reflect a 77 cent Canadian dollar.

[3] A copy of the plan is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab1*.

4.0 CUSTOMER AND ENERGY FORECAST

Introduction

Appendix B provides the actual customer and energy sales for 2009 - 2014 along with the forecast under both existing and proposed rates for the 2015 - 2017. Over the past 5 years the robust economic performance of the province's economy resulted in average annual customer and energy sales growth of 1.6% and 2.2%, respectively.

Given the province's struggling economy forecast customer and energy sales growth will be much lower than experienced in recent years. The total number of customers is forecast to increase by 0.9% in 2015, 0.8% in 2016 and 0.7% in 2017. Energy sales under existing rates are forecast to increase by 1.1% in 2015, 0.5% in 2016 and 0.4% in 2017. Energy sales under proposed rates, which include the elasticity effects of the proposed 3.1% increase, are forecast to increase by 1.1% in 2015, 0.4% in 2016 and 0.1% in 2017.

Domestic

Growth in the number of Domestic customers is largely a result of housing starts. The Conference Board of Canada forecasts housing starts of 1,632 units in 2015, 1,329 in 2016 and 1,226 in 2017 while Canada Mortgage and Housing Corporation is projecting 1,950 units in 2015 and 1,900 in 2016[4]. Using an average of these forecasts, the number of domestic customers is forecast to grow by 0.9% in 2015, 0.8% in 2016 and 0.7% in 2017.

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 remain flat in 2015, and decrease by 0.1% in 2016 and 0.4% in 2017.

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 1.2% in 2015, 0.6% in 2016 and 0.3% in 2017.

General Service

In the small general service rate class 2.1 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 0.5% in 2015, 0.4% in 2016 and 2017. Under proposed rates the volume of general service energy sales is forecast to grow by 1.0% in 2015, and decrease by 0.1% in 2016 and 0.3% in 2017. The decrease in energy sales is directly related to the winding down of construction at Vale's hydromet facility in Long Harbour and the completion of the gravity based structure for the Hebron offshore oil project.

[4] Canada Mortgage and Housing Corporation forecast for 2017 is not available.

Together these projects will negatively impact general service energy sales by 23.5 GWh in 2016 and by an additional 23.6 GWh in 2017.

Street and Area Lighting
In the street and area lighting class, the number of customers is forecast to grow by 0.8% in 2015 and 0.7% in 2016 and 0.6% in 2017. The volume of energy sales is forecast to increase by 0.6% in 2015, 0.3% in 2016 and 0.6% in 2017.

Produced and Purchased
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 in 2015, 2016 and 2017.

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 2010 Hydro Normal Production Review completed in February 2011. This study recommended a Normal Production of 430.5 GWh.

The study also recommended that Normal Production be adjusted annually to reflect the impact on production of any scheduled outages in the year, and that adjustments also be made to reflect the impact on production of physical changes to the plants. Since the completion of the study, modifications have been made to a number of plants and Normal Production has been revised to 435.1 GWh in 2015.

The refurbishment of the Tors Cove and Rocky Pond Hydro Plant in 2015 will result in lost production of 3.1 GWh reducing the Normal Production to 432.0 GWh. In addition, the Company produced 1.0 GWh at various thermal plants increasing total production for 2015 to 433.0 GWh.

Normal Production is projected to decrease to 427.1 GWh in 2016[5] and increase to 436.5 GWh in 2017.[6] These changes to Normal Production reflect plant availability and modifications to plants that will impact production.

5 In 2016 Normal Production will increase from 435.1 GWh to 438.4 GWh as a result of the refurbishment of the Tors Cove and Rocky Pond Hydro Plant in 2015. A major refurbishment of the Pierre's Brook Hydro plant in 2016 will result in lost production of 11.3 GWh reducing the Normal Production to 427.1 GWh.

6 Normal Production in 2017 is expected to remain unchanged from 2016 at 438.4 GWh. However, planned work at the Tors Cove Hydro Plant will result in lost production of 1.9 GWh reducing the normal to 436.5 GWh in 2017.

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. Newfoundland Power's purchased demand is then derived by subtracting load curtailment by Newfoundland Power customers and company owned facilities and 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 0.0%. In 5 of the past 10 years, differences from forecast were 1% or less. In 2015 energy sales are projected to be lower than forecast by 0.6%.

Newfoundland Power Inc.

Key Economic Indicators[1]
2009 - 2017F

(millions of dollars)

	Actual			Forecast					
Indicator	**2009**	**2014**	**Average Growth**	**2015**	**Change From 2014**	**2016**	**Change From 2015**	**2017**	**Change From 2016**
Gross Domestic Product ($ 2007)									
Goods Producing Industries	12,235	13,195	1.5%	13,093	-0.8%	12,580	-3.9%	12,315	-2.1%
Service Producing Industries	12,709	14,312	2.4%	14,408	0.7%	14,489	0.6%	14,690	1.4%
Total of All Industries	24,868	26,924	1.6%	26,919	0.0%	26,486	-1.6%	26,422	-0.2%
Consumer Price Index (2002=100)	114.6	128.4	2.3%	129.2	0.7%	133.5	3.3%	136.2	2.0%
Household Disposable Income ($ 2002)	11,560	13,453	3.1%	13,548	0.7%	13,204	-2.5%	13,241	0.3%
Unemployment Rate (%)	15.6%	12.0%	N/A	12.6%	N/A	12.1%	N/A	11.8%	N/A
Housing Starts - Units	3,057	2,119	N/A[2]	1,632	-23.0%	1,329	-18.6%	1,226	-7.8%
Canadian GDP Deflator (2007=100)	101.7	113.0	2.1%	113.1	0.1%	115.5	2.1%	117.9	2.1%
Canada Mortgage and Housing Corporation[3]									
Housing Starts - Units	3,057	2,119	N/A[2]	1,950	-8.0%	1,900	-2.6%	-	-

[1] Conference Board of Canada, Provincial Outlook Summer 2015, Economic Forecast, Dated: July 16, 2015.
[2] The average number of housing starts during the past 5 years was 3,192 units.
[3] Canada Mortgage and Housing Corporation, Housing Market Outlook, Second Quarter, 2015. Forecast is not available for 2017.

Newfoundland Power Inc.

Customer and Energy Forecast
2009 - 2017F

		Actual			Forecast		Existing				Proposed			
		2009	2014	Average Growth	2015	Change From 2014	2016	Change From 2015	2017	Change From 2016	2016	Change From 2015	2017	Change From 2016
Customers														
Domestic														
Regular	1.1	207,335	222,935	1.5%	224,939	0.9%	226,704	0.8%	228,327	0.7%	226,704	0.8%	228,327	0.7%
Seasonal	1.1	-	1,889	-	1,900	0.6%	1,950	2.6%	2,000	2.6%	1,950	2.6%	2,000	2.6%
Total Domestic		207,335	224,824	1.6%	226,839	0.9%	228,654	0.8%	230,327	0.7%	228,654	0.8%	230,327	0.7%
General Service														
0-100 kW (110 kVA)	2.1	20,806	22,013	1.1%	22,157	0.7%	22,255	0.4%	22,345	0.4%	22,255	0.4%	22,345	0.4%
110 kVA (100 kW) - 1000 kVA	2.3	1,088	1,241	2.7%	1,216	-2.0%	1,223	0.6%	1,233	0.8%	1,223	0.6%	1,233	0.8%
1000 kVA and Over	2.4	68	70	0.6%	63	-10.0%	63	0.0%	63	0.0%	63	0.0%	63	0.0%
Total General Service		21,962	23,324	1.2%	23,436	0.5%	23,541	0.4%	23,641	0.4%	23,541	0.4%	23,641	0.4%
Street and Area Lighting	4.1	10,010	10,731	1.4%	10,818	0.8%	10,894	0.7%	10,963	0.6%	10,894	0.7%	10,963	0.6%
Total Customers		239,307	258,879	1.6%	261,093	0.9%	263,089	0.8%	264,931	0.7%	263,089	0.8%	264,931	0.7%
Energy Sales (GWh)														
Domestic														
Regular	1.1	3,203.3	3,595.3	2.3%	3,638.5	1.2%	3,668.0	0.8%	3,697.3	0.8%	3,660.9	0.6%	3,672.5	0.3%
Seasonal	1.1	-	17.8	-	17.2	-3.4%	17.5	1.7%	18.2	4.0%	17.5	1.7%	18.2	4.0%
Total Domestic		3,203.3	3,613.1	2.4%	3,655.7	1.2%	3,685.5	0.8%	3,715.5	0.8%	3,678.4	0.6%	3,690.7	0.3%
General Service														
0-100 kW (110 kVA)	2.1	730.7	782.8	1.4%	791.3	1.1%	801.6	1.3%	807.6	0.7%	800.7	1.2%	804.5	0.5%
110 kVA (100 kW) - 1000 kVA	2.3	890.5	965.1	1.6%	1,002.9	3.9%	1,004.9	0.2%	1,015.7	1.1%	1,004.9	0.2%	1,015.7	1.1%
1000 kVA and Over	2.4	438.0	505.6	2.9%	481.1	-4.8%	468.4	-2.6%	446.8	-4.6%	468.4	-2.6%	446.8	-4.6%
Total General Service		2,059.2	2,253.5	1.8%	2,275.3	1.0%	2,274.9	0.0%	2,270.1	-0.2%	2,274.0	-0.1%	2,267.0	-0.3%
Street and Area Lighting	4.1	36.5	31.9	-2.7%	32.1	0.6%	32.2	0.3%	32.4	0.6%	32.2	0.3%	32.4	0.6%
Total Energy Sales		5,299.0	5,898.5	2.2%	5,963.1	1.1%	5,992.6	0.5%	6,018.0	0.4%	5,984.6	0.4%	5,990.1	0.1%
Company Use		11.6	12.3	1.2%	11.9	-3.3%	11.9	0.0%	11.9	0.0%	11.9	0.0%	11.9	0.0%
Losses		303.2	336.2	2.1%	341.1	1.5%	342.8	0.5%	344.2	0.4%	342.3	0.4%	342.6	0.1%
Produced & Purchased		5,613.8	6,247.0	2.2%	6,316.1	1.1%	6,347.3	0.5%	6,374.1	0.4%	6,338.8	0.4%	6,344.6	0.1%
Wheeled		77.9	103.7	5.9%	104.5	0.8%	104.7	0.2%	102.4	-2.2%	104.7	0.2%	102.4	-2.2%
Total System Energy		5,691.7	6,350.7	2.2%	6,420.6	1.1%	6,452.0	0.5%	6,476.5	0.4%	6,443.5	0.4%	6,447.0	0.1%

Newfoundland Power Inc.

Purchased Energy and Demand Forecast
2015 - 2017F

Year	Produced Purchased & Wheeled	Total Wheeled Energy	Total Produced & Purchased (NP Native Peak)			Total Curtailed Demand	NP Produced		Total Purchased	
				(1)	(2) Load	(3)	(4)	(5) Credit		(6)
Year	GWH	GWH	GWH	MW	Factor	MW	GWH	MW	GWH	MW
Existing										
2015	6,420.6	104.5	6,316.1	1,404.94	51.32%	11.0	433.0	117.93	5,883.1	1,276.01
2016	6,452.0	104.7	6,347.3	1,408.02	51.32%	11.0	427.1	117.93	5,920.2	1,279.09
2017	6,476.5	102.4	6,374.1	1,417.84	51.32%	11.0	436.5	117.93	5,937.6	1,288.91
Proposed										
2015	6,420.6	104.5	6,316.1	1,404.94	51.32%	11.0	433.0	117.93	5,883.1	1,276.01
2016	6,443.5	104.7	6,338.8	1,406.14	51.32%	11.0	427.1	117.93	5,911.7	1,277.21
2017	6,447.0	102.4	6,344.6	1,411.28	51.32%	11.0	436.5	117.93	5,908.1	1,282.35

Notes:

1. Native peak is the maximim demand forecast to be served by Newfoundland Power. The 2015 native peak reflects the forecast for the winter period of December 2015 to March 2016.
2. Load Factor is based on an average of 15 year historical (normalized) load factors.
3. Based on historical performance of participants plus curtailment of company owned facilities.
4. Normal production for the forecast period is 435.1 GWh adjusted for plant availability and efficiency improvements. Produced for 2015 also includes 1.0 GWh for production at Newfoundland Power's thermal plants.
5. Assumes a generation credit of 117.93 MW.
6. The purchased demand for 2015 reflects the purchased demand from Newfoundland and Labrador Hydro for the winter period of December 2015 to to March 2016 and represents Newfoundland Power's forecast billing demand for 2016.

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 (%)
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
2009	5,244.5	5,299.0	54.5	1.0
2010	5,349.9	5,419.0	69.1	1.3
2011	5,480.0	5,552.8	72.8	1.3
2012	5,658.1	5,680.6	22.5	0.4
2013	5,763.6	5,763.3	-0.3	0.0
2014	5,835.6	5,898.5	62.9	1.1
2015	5,997.2	5,963.1 [3]	-34.1	-0.6

Notes:

[1] Sales for 2005 is reported on a billed basis while amounts for 2006 - 2015 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 2008, 2010, 2013 and 2014 forecasts were the basis for the revenue requirement determinations presented as part of the Company's General Rate Applications filed in 2007, 2009 and 2012, respectively.

[3] The actual sales figures for 2015 represent the forecast contained in this application.

Conference Board of Canada
Provincial Outlook Summer 2015
Economic Forecast
Dated: July 16, 2015

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PROVINCIAL OUTLOOK

Economic Forecast.

SUMMER 2015

The Conference Board of Canada

Provincial Outlook Summer 2015: Economic Forecast
by *The Conference Board of Canada*

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Preface

The *Provincial Outlook Summer 2015* was prepared by Marie-Christine Bernard, Associate Director, under the general direction of Pedro Antunes, 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.

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Executive Summary

Marie-Christine Bernard

Another Tough Year

At a Glance

- The Canadian economy did not perform well over the first few months of the year and is flirting with recession, but growth will pick up through the rest of 2015 and in 2016.
- The trade sector performed poorly in the first part of the year, leading to downgrades of the Quebec and Ontario economic forecast for 2015.
- Saskatchewan, along with Alberta, will see a contraction in its economy with adverse weather hurting agriculture yields and a correction in oil prices having led to a severe downturn in the energy sector.
- The near-term economic outlook is better for New Brunswick and Nova Scotia after years of sluggish growth and job losses.

NATIONAL OVERVIEW

The Canadian economy contracted slightly in the first four months of the year, posted a near-record trade deficit in May, and has been hit hard by the uncertainty in the eurozone. As a result, expectations have dimmed that the economy actually did post growth in the second quarter, fuelling speculation that the Canadian economy has dipped into recession. With four months of data available for 2015 so far, real gross domestic product has now shrunk in every month as lower oil prices and turbulence from external events—such as the Greek debt crisis—have hurt the Canadian economy. We now expect the numbers to show that economic growth tracked close to zero in the second quarter as the economy flirted with recession. However, it is not all bad news. Although employment fell by 6,400 in June, the economy has added 16,000 jobs a month on average over the first half of the year; not strong job growth, but it is positive growth and better than what we saw through most of 2014. Moreover, all the gains have been in full-time positions, more than offsetting a decline in part-time work. Finally, wage growth accelerated in May and June and should post modest gains over the near term. Consequently, even if Canada has slipped into recession, we expect it will be a mild one, with growth picking up through the rest of the year. Nonetheless, given the weak start to the year, we anticipate that growth for 2015 to come in at just 1.6 per cent, the worst showing since 2009.

Business investment will be the weakest part of the Canadian economy in 2015. Oil prices fell precipitously at the end of last year and, in late July, now dipped back to under US$50 a barrel. With weaker profits and cash flows, oil firms responded by slashing engineering projects and mineral exploration by 15 per cent in the first quarter. For 2015 and 2016 as a whole, we project that oil and gas firms will chop their capital budgets by almost one-third. Given that investment in the oil and gas sector currently represents almost one-third of total business investment, the cuts will have a sizable impact on the overall economy.

Firms have been hesitant to invest, even those outside of the energy sector. Purchases of machinery and equipment declined substantially in the first quarter. If we are to believe the recent survey of investment intentions from Statistics Canada, these declines are likely to continue throughout the year. According to this survey, businesses are planning to reduce their purchases of machinery and equipment by 5.2 per cent this year, a fall-off even more negative than our own projection. And, given the substantial erosion in the value of the loonie (which makes imported machinery and equipment more expensive), a bleak picture exists for the volume of investment. Building construction is also expected to see substantial decreases through 2015. Even with no increase in construction last year and a large drop in the first quarter of 2015, the vacancy rate has risen to its highest level since 2005. Building permits, a leading indicator for the construction industry, were down almost 15 per cent on a year-over-year basis in May, further supporting our belief that a downturn in construction activity is under way.

Although households are enjoying big savings at the gas pump and federal tax cuts, real household spending should also weaken this year. Soft employment growth, mostly weak wage gains, a high level of household debt, easing real estate markets, and job losses in oil-rich provinces will combine to take some of the steam out of real consumer spending in 2015. In addition, the economy is unlikely to get more than a small boost from government spending. Although we expect a slight increase in infrastructure spending, the federal and provincial governments were planning—even before the decline in oil prices—to maintain a significant degree of the current spending restraint. Now, with low oil prices and weak growth taking a bite out of revenue growth, an even greater level of restraint is foreseen.

The only area of the economy where we anticipate solid growth this year is the trade sector, but even here there are concerns. Trade numbers to date have been disappointing, with merchandise exports declining through the first five months of this year. In May, they were down 6.7 per cent from the same time last year. Although the Canadian dollar remains low (which should boost trade), the U.S. economy started 2015 on a weak note, as poor weather conditions and a labour strike at West Coast ports took a huge bite out of U.S. economic activity in the first quarter. On the bright side, the U.S. economy has already shown signs of bouncing back, and the expected uptick in U.S. activity over the remainder of 2015 and throughout 2016 should be good news for Canada's export sector.

Given our projection of only modest economic growth, we expect the economy to add just 150,000 jobs this year—another poor performance after 2014, which saw the weakest increase since 2009. Job growth is projected to accelerate in 2016 with 192,000 new jobs. This year, the unemployment rate will rise slightly to reach 7 per cent by the fourth quarter, before drifting back to 6.8 per cent by the end of 2016. Although conditions are weaker than we previously estimated, we expect the Bank of Canada to stand pat on further interest rate cuts following its quarter-point cut on July 15 and to begin raising rates again in late 2016 as the economy strengthens. We are looking for economic growth of 2.1 per cent in 2016.

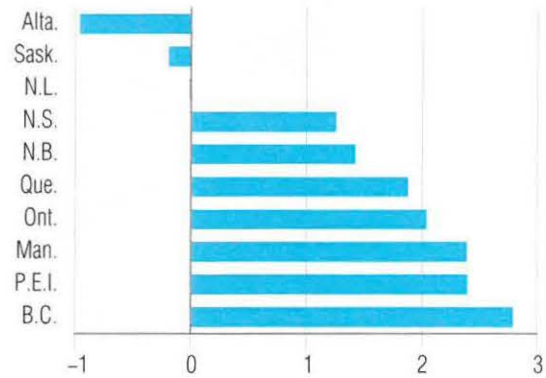
PROVINCIAL OVERVIEW

With Alberta's economy not performing well due to the lower oil prices, all eyes were on Central Canada as the lower Canadian dollar and the anticipated improvements in economic conditions south of the border were to revive growth in the Ontario and Quebec economy. But, more than midway through the year, economic forecasts are being revised down for nearly all provinces. Central Canada's economic rebound will be more moderate than first envisioned as exports failed to keep up with the acceleration that got under way in 2014. A host of factors, some temporary, some more structural, have plagued exporters in Canada's manufacturing heartland since the beginning of the year.

Difficulties in the oil sector will be hitting the Alberta, Saskatchewan, and Newfoundland and Labrador economies hard. Troubles never come alone; very dry weather conditions out west will also hamper prospects for a better harvest and that too will impact economic growth. While a lot of the weakness in the Canadian economy so far this year is due to the correction in the energy sector, economic growth outside the energy sector has been slow to pick up. It has been difficult for the metal mining sector; it is currently experiencing some turbulence as the end of the commodity boom rattles growth prospects going forward. Most projects in the mining sector have faced difficulties in securing financing and have not been able to move from proposal to development phase; this includes projects that are nearly shovel-ready. This atmosphere has softened considerably the outlook for the metal mining sector for the next few years. In addition, business investment in general remains depressed in several provinces so far this year. Although current economic conditions are far from stellar and are only slowly improving in Central and Atlantic Canada, we do not expect the weakness to linger in the second half of the year. In fact, we are foreseeing a more normal economic performance in most of the provinces over the rest of the year and in 2016 as economic conditions stabilize in Western Canada and the stronger U.S. economy helps improve the trade outlook for Central Canada.

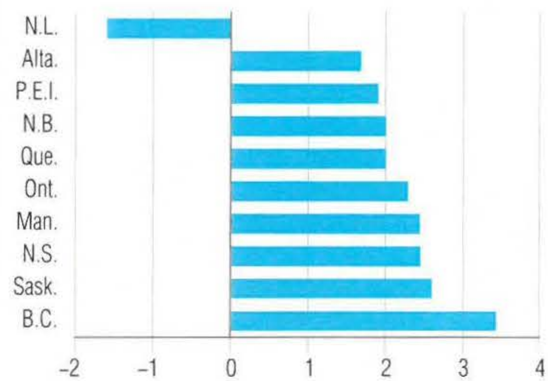
Regionally, British Columbia, Manitoba, Prince Edward Island, and Ontario will be the leaders in real GDP growth this year and the only provinces with growth of 2 per cent or more. (See Chart 1.) In 2016 (see Chart 2), while the economy is fairly stable in Manitoba despite the more volatile conditions in the resource sector, British Columbia will see the strongest real GDP growth in 2016. Recent developments have led us to include one major investment in B.C. (a liquefied natural gas [LNG] terminal) over the near term. (See Chart 2.)

Chart 1
Real GDP by Province, 2015
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Real GDP by Province, 2016
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

PROVINCIAL ASSUMPTIONS

Newfoundland and Labrador's economy is not doing well. All key economic indicators are down in the first half of the year and weakness in the economy will persist for the next few years. The downturn in the economy is due to both cyclical and structural factors. The correction in oil, metal, and mineral prices is hurting production and investment decisions. But, even when the commodity market improves, the economy will fail to recover quickly. The aging of the population is going to hurt the ability of Newfoundland and Labrador—more than any other province in Canada—to generate the type of growth seen in the last decade. With a drop in employment, retail sales, and housing starts plus a large correction in the existing resale market, overall real GDP is not projected to grow at all in 2015 and to decline by 1.6 per cent in 2016. Some areas of the economy are expanding strongly, areas such as manufacturing where processing has begun at the Long Harbour hydromet plant.

While the economy in Canada is limping along, Prince Edward Island's seems to be in good health despite poor job creation. Following solid job gains between 2010 and 2013 (one of the strongest performances in the country), the Island's job market has stalled. Nevertheless, the economy is performing well on a number of fronts, particularly in the manufacturing and primary sectors. In addition, the retreat of the Canadian dollar should help tourism enjoy healthy growth and this will help the economy advance by 2.4 per cent in 2015 and 1.9 per cent in 2016.

Nova Scotia's economy is struggling to gain momentum and economic growth will be weaker this year than last. The new natural gas production from Encana's Deep Panuke offshore field was supposed to boost economic growth, but difficulties have hampered production to date as well as the production capacity of the field; this is weighing on growth. Aside from the petroleum industry, the economy appears to be gaining traction, mainly in the manufacturing and construction industries. However, the province has been unable to reverse a two-year trend in job creation and the job market will fail to generate any new jobs once again in 2015. The numbers are probably influenced by the downturn in the energy sector in the West; rotational workers who have lost their jobs there are counted in the workforce of their province of origin. Nevertheless, with work getting under way on the Arctic patrol vessels at Irving's newly expanded shipyard this fall, the economy should see real GDP growth accelerate from just 1.3 per cent in 2015 to 2.5 per cent in 2016.

In New Brunswick, the economic outlook is modest but much better than in recent years. Recovery in the job market remains elusive but a number of industries—such as manufacturers and industries in the forestry sector—are facing better growth prospects. The services sector should benefit from the more upbeat performance of the goods-producing sector that is helping to revive job creation and overall economic growth. New Brunswick's real GDP, after experiencing declines since 2011, is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Quebec's economic performance is being pulled down by the large contraction in exports. It will be difficult for the province's economy to gain sufficient momentum in the latter half of the year to boost economic growth to or above 2 per cent. With consumer demand that is still fairly strong, overall economic growth of 1.9 per cent is expected for 2015, a modest performance but one that still outpaces the national growth rate of just 1.6 per cent. While exports are projected to improve going forward, the aerospace industry will feel the effects of a weaker demand for business jets and the thousands of layoffs announced by Bombardier earlier this year. With stronger U.S. economic growth forecast for 2016, business investment should slowly pick up with positive growth in both non-residential and machinery and equipment investment. A number of large projects, mainly in the mining sector, could go ahead in the next few years if conditions improve; however, until then, investment in the province is forecast to advance only modestly. In 2016, the overall Quebec economy will maintain the same pace as this year, with a projected growth of 2 per cent. Fiscal restraints will continue to curb government expenditures on both programs and infrastructure. In addition, the housing market is weakening and is not expected to contribute positively to the economy.

In Ontario, the economy got off to a slow start this year as real exports fell 2 per cent in the first quarter and are very likely to contract in the second quarter as well. Ontario's disappointing trade performance will moderate its overall growth projections in 2015 to 2 per cent. Most of this growth will be concentrated in the second half of the year. The positive momentum will carry over to 2016 when real GDP is forecast to expand by 2.3 per cent. While the trade sector has faced challenges, the domestic economy in general is holding strong. Consumer demand will benefit from the sound job creation and stronger growth in household disposable income. While there are concerns of overbuilding in Toronto's condo market, the housing sector (both new and resale markets) remains very strong.

If job creation is any indication, Manitoba's economy is on solid ground. Employment is forecast to grow by 1.7 per cent in 2015 and 1.4 per cent in 2016. Real GDP growth is expected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping the province among the provincial growth leaders. Steady gains are forecast in manufacturing, agriculture, and construction.

Manitoba is not facing the same pressures in the agriculture sector as are neighbouring Saskatchewan and Alberta.

Saskatchewan, along with Alberta, will face negative real GDP growth this year. The correction in oil prices has hurt the economy and now drought conditions will hamper crop yields. Overall, real GDP growth is expected to contract by 0.2 per cent in 2015 but, if the wheat harvest is more affected than expected by the adverse weather, the decline in real GDP could be steeper. The economic outlook should be stronger in 2016 as we do not foresee another major correction in the oil industry. Sound growth is also forecast for uranium and potash production and for the construction industry. All things considered, Saskatchewan's economy is projected to rebound by 2.6 per cent in 2016.

With the swift slide in crude oil prices, Alberta's economy was bracing for difficult times and it has not been smooth sailing for the province so far this year. Support activities for mining and oil and gas extraction shrank significantly over the winter drilling season as rigging and drilling services retreated by close to 35 per cent. As well, petroleum companies have announced staff layoffs and cuts to their capital plans to expand the energy sector. Employment growth is still positive but much weaker than in previous years. There is nothing more unpredictable than commodity prices, and low oil prices could likely last all of next year. The current global oversupply of oil remains a dominant factor influencing oil prices. Nonetheless, there should be more stability in the Alberta economy in 2016 and we anticipate that overall real GDP will advance by 1.7 per cent next year, following a 1 per cent decline in 2015.

There are new developments in the natural gas industry. British Columbia recently passed legislation to enter into an agreement with Petronas to build the Pacific NorthWest LNG export terminal near Prince Rupert. The project would rival the large megaprojects in Alberta's oil sands and would be the largest private investment in the province's history. If all conditions are met, construction on this first multi-billion-dollar LNG terminal could start in 2016. Meanwhile, British Columbia has been enjoying solid economic growth; no other province is facing such enviable prospects.

The provincial economy is expected to advance by a solid 2.8 per cent in 2015 and by 3.4 per cent in 2016. The housing market remains hot with both new and resale markets making robust gains this year. The job market is performing well and consumers are expected to boost retail sales by a robust 7.3 per cent this year despite falling gasoline prices. Manufacturing should see a strong performance, benefiting from the rebounding U.S. economy, the lower Canadian dollar, and new shipbuilding work at North Vancouver's Seaspan shipyard for non-combat vessels.

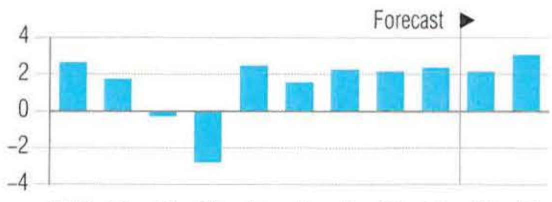
U.S. OUTLOOK

The U.S. economy stumbled badly in the first quarter as real GDP declined. Fortunately, the economy performed better in the second quarter, as evidenced by the encouraging employment reports for May and June. However, the strong value of the greenback, among other factors, continues to restrain growth somewhat and it is only now, in the second half of the year, that economic growth is likely to hit the 3 per cent range. The weakness in the economy in the first quarter will likely delay interest rate increases until the fall, depending on how events unfold over the next few months. We expect real GDP to expand by 2.2 per cent for this year as a whole and to grow by 3.1 per cent in 2016. (See Chart 3.)

As noted, the U.S. economy slumped in the first quarter of this year. While a number of temporary factors, such as winter storms and a labour strike (now settled) at West Coast ports did hurt export growth, it would be misleading to blame the weakness in the U.S. economy on just temporary factors. Investment in energy projects is declining quickly, while the higher value of the U.S. dollar has hurt export and manufacturing activity.

In the first part of 2015, the negative effects of lower oil and gasoline prices outweighed the positives for the U.S. economy. Real investment in non-residential structures, which captures the bulk of energy investment, was down 21 per cent (at annual rates) in the first quarter, and the another decline is anticipated for the second quarter. Rig counts have dropped by more than 50 per cent since last November—evidence of the impact that world oil prices in the US$50 to US$60 range are

Chart 3
U.S. Economy Disappoints but the Outlook Is Robust
(U.S. real GDP, percentage change*)



*based on 2005 US$
f = forecast
Sources: The Conference Board of Canada; U.S. Bureau of Economic Analysis (BEA).

having on this sector of the economy. However, no large correction is foreseen in energy investment in the second half of this year. Therefore, with energy investment no longer falling, overall investment in non-residential construction should expand at a slightly positive pace in the second half of this year and by 3.2 per cent in 2016.

The supposed positive effect on household spending attributable to sharply lower gasoline prices failed to materialize as many households increased their savings. During past periods of tumbling gasoline prices, it has always taken some time before Americans started to spend the money they saved from lower gasoline prices; this time is no different. However, we do expect consumer spending to increase at a faster clip in the second half of this year as households finally respond to lower prices at the pump and ramp up their purchases of goods and services. Real consumer spending is forecast to increase by 3.1 per cent this year and 3.3 per cent in 2016.

The anticipated rebound in household spending is readily apparent from the latest vehicle sales data. In May, car sales surged to 17.8 million units (seasonally adjusted at annual rates), up from 16.5 million in April. And, although the gain was weaker in June, this was widely projected, given the surge in sales in May. While some of the increase in car sales is linked to the catch-up effect following the harsh winter, there are other factors boosting sales. Labour markets are improving to the point where wages are finally starting to post some meaningful gains. In the first six months of this year, the economy created jobs at an average monthly pace well above 200,000. Also, lenders are more receptive to providing credit for more risky borrowers, while financing terms have maintained vehicle affordability at high levels.

We expect the U.S. Federal Reserve to increase interest rates this autumn for the first time since 2006, as monetary authorities are confident that the economy is strong enough to handle higher rates. But future interest rate increases are projected to be modest. The Fed remains concerned about some pockets of weakness in the economy, such as the number of long-term unemployed.

MONETARY POLICY

The rapid fall in oil prices over the second half of 2014 and early 2015 drove year-over-year price growth in many countries into negative territory. As the impact of the energy price decline fades, inflation is set to return. While price growth did not turn negative in Canada, it has been restrained so far this year by the large drop in oil prices. Changes in energy prices directly affect the gasoline and fuel oil components of the consumer price index (CPI) and indirectly affect inflation through their impact on economic growth. Weak economic growth means sluggish demand, and this has helped to keep price pressures from building in the first part of this year. On the other hand, the drop in oil prices triggered a depreciation of the Canadian dollar, which is making imported goods more expensive and is adding to current price growth. Overall, headline inflation remains weak, posting growth of 1 per cent in June, while core inflation grew at a 2.1 per cent pace.

In the near term, we expect that the impact of higher import prices will continue to offset weakness stemming from sluggish demand and, therefore, that core inflation will remain at or above 2 per cent over the forecast period. However, aside from transitory impacts (such as those from exchange rate pass-through), the main factor influencing growth in trend prices is the output gap. The output gap is the difference between Canada's estimated potential and its actual output and, when the gap is negative, the economy can grow above its potential without igniting inflationary pressures. The contraction in real GDP growth in the first quarter widened the output gap but, with growth resuming in the second half of this year, the gap will continue to shrink and will fall below 1 per cent in early 2016. The steady decline in the output gap will eventually lead to inflationary pressures, but the Bank of Canada is expected to be patient about raising rates to ensure that any hikes do not derail the economic recovery. Our forecast assumes that monetary authorities will delay raising rates until at least September 2016. It also assumes that the divergence in policy between the Bank of Canada (which cut its key rate another quarter point on July 15) and the U.S. Federal Reserve (which is expected to raise rates before the end of this year) will keep the loonie around US$0.80 until the second half of next year despite a slow and steady rise in oil prices. (See Chart 4.)

Chart 4
Rate Hike in the U.S. to Take Place Sooner Rather Than Later
(U.S. and Canadian three-month T-bills spread, per cent)

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

FISCAL OUTLOOK

The economy will not get much of a boost from the government sector over the forecast period. For years, most provinces—and Canada as a whole—have been waiting for a strong post-recession bounce-back in economic growth. However, with Canada's potential output growth slowing due to an aging population and lacklustre investment outside of the energy sector, we are no longer forecasting a substantial rebound in economic growth. Indeed, annual real GDP growth is not expected to exceed 2.3 per cent at any point over the next five years. This slowdown in GDP growth is moderating gains in government revenues and forcing governments to slow the pace of their spending in order to avoid a return to deficit or a sharp increase in their ongoing deficits. Despite weak spending on goods and services, total public spending looks to improve over the next few years, due mostly to a modest increase in infrastructure investment. After declining last year, real public consumption and investment spending is set to grow by a modest 0.8 per cent this year, followed by an increase of 0.9 per cent in 2016.

Most provinces are still running deficits and the federal government is expecting only small surpluses, which are predicated on continued spending restraint. For the federal government to meet its budget targets, it must continue to tightly control spending. When inflation is taken into account, federal spending on goods and services has declined in each of the last four years. And declines are anticipated again this year and in 2016. This restraint should allow the federal government to post small surpluses (unadjusted for contingency amounts) of $2.7 billion this fiscal year and $3.2 billion in fiscal 2016–17.

While the federal government looks able to handle the lower revenue outlook without returning to deficit, the provincial governments are not in as strong a fiscal position and they will have difficulty coping with this lower growth environment. Most of the provinces have tabled their 2015 budgets, and the outlook for this fiscal year is sobering. After posting a collective deficit of $13.7 billion in fiscal 2014–15, the collective provincial deficit is set to widen to $15 billion this fiscal year. Going forward, the provinces are facing slower-than-average revenue growth, a drop in resource royalties, and a growing demand for provincially funded services—a combination that will make it difficult for them to return to surplus any time soon.

Marie-Christine Bernard

Une autre année difficile

Aperçu

- L'économie canadienne n'a pas inscrit de bons résultats dans les premiers mois de l'année et elle frôle la récession, mais la croissance sera plus forte d'ici la fin de 2015 et aussi en 2016.
- Le secteur du commerce extérieur a connu un début d'année difficile, si bien que les prévisions économiques du Québec et de l'Ontario pour 2015 ont été révisées à la baisse.
- La Saskatchewan, comme l'Alberta, subira une contraction de son économie, car le mauvais temps y perturbe les récoltes et la correction des prix du pétrole porte un dur coup au secteur de l'énergie.
- Après des années de faible croissance et de pertes d'emploi, les perspectives économiques du Nouveau-Brunswick et de la Nouvelle-Écosse sont meilleures à court terme.

VUE D'ENSEMBLE NATIONALE

L'économie canadienne s'est légèrement contractée dans les quatre premiers mois de l'année, accusant un déficit commercial quasi record en mai, et s'est nettement ressentie des incertitudes planant sur la zone euro. Cela porte à croire que l'économie aura difficilement pu progresser au deuxième trimestre et, de plus en plus, que le Canada pourrait se trouver en récession. Les données des quatre premiers mois, celles dont nous disposons pour 2015, montrent que le produit intérieur brut (PIB) a diminué pendant ces mois sous l'effet combiné de la baisse des prix réduits du pétrole et des perturbations d'origine étrangère, notamment la crise de la dette grecque. Nous croyons que les statistiques montreront que la croissance économique aura avoisiné le zéro au deuxième trimestre, l'économie frôlant la récession. Mais tout n'est pas si négatif. Ainsi, même si 6400 postes ont disparu en juin, 16 000 emplois se sont créés en moyenne par mois durant les six premiers mois de l'année. Il ne s'agit pas d'une forte progression de l'emploi, mais quand même d'une évolution positive, supérieure à celle observée généralement en 2014. De plus, les gains sont faits dans les emplois à temps plein et ils compensent amplement les pertes inscrites dans les emplois à temps partiel. Enfin la croissance des revenus de travail s'est améliorée en mai et juin et devrait s'intensifier quelque peu à court terme. Par conséquent, si le Canada est en récession, nous estimons que cela sans grande ampleur puisque la croissance sera plus importante dans les mois qui viennent. Néanmoins, compte tenu d'un lent début d'année, nous prévoyons que la croissance sera de 1,6 % à peine en 2015, le résultat le plus faible depuis 2009.

Les investissements des entreprises seront le maillon faible de l'économie canadienne en 2015. Le baril de pétrole a vu son prix dégringoler à la fin de 2014 et il était à moins de 50 $ US à la fin juillet de cette année. Avec des bénéfices et des flux de trésorerie en recul, les sociétés pétrolières ont réagi en réduisant de 15 % leurs projets d'ingénierie et d'exploration minière au premier trimestre. Pour l'ensemble de 2015 et 2016, nous estimons que ces entreprises réduiront de près du tiers leurs budgets d'immobilisations. Or, puisque les investissements dans le secteur pétrolier et gazier représentent le tiers, ou à peu près, de l'ensemble des investissements canadiens des entreprises, ces décisions auront des conséquences considérables dans toute l'économie.

Même ailleurs que dans le secteur énergétique, les entreprises hésitent à investir. Les achats de matériel et d'outillage ont beaucoup diminué au premier trimestre et, selon le récent sondage de Statistique Canada sur les intentions d'investir, ces baisses devraient se poursuivre toute l'année. Ce sondage révèle que les entreprises comptent réduire de 5,2 % leurs achats de matériel et d'outillage cette année, une réduction plus marquée que ce que nous avions prévu. Et vu l'érosion importante du huard (la perte de valeur rend le matériel et l'outillage importés plus chers), les perspectives d'investissement sont peu reluisantes. La construction d'immeubles devrait elle aussi chuter de façon importante en 2015. Et même si la construction n'a pas augmenté l'an dernier et qu'un recul marqué a été observé au premier trimestre, le taux d'inoccupation est à son plus haut niveau depuis 2005. Les permis de bâtir, un indicateur clé de l'industrie de la construction, étaient en baisse de près de 15 % en mai par rapport à mai l'an dernier, ce qui confirme notre perception quant au ralentissement de l'activité dans le secteur de la construction.

En dépit d'importantes économies à la pompe et des réductions d'impôt au palier fédéral, la croissance des dépenses réelles des ménages devrait elle aussi diminuer cette année. La croissance léthargique de l'emploi, et particulièrement la faible progression des salaires, le fort endettement des ménages et le ralentissement du marché immobilier s'ajouteront aux pertes d'emploi dans les provinces riches en pétrole pour tempérer quelque peu les dépenses de consommation en 2015.

En outre, les dépenses publiques contribueront assez peu à l'essor économique, au mieux. Nous entrevoyons une augmentation des dépenses en infrastructures, mais elle sera mince, car même avant la chute des prix du pétrole, le gouvernement fédéral et les provinces disaient vouloir sérieusement continuer à limiter les dépenses courantes. Et maintenant, les cours du pétrole agissant de façon négative sur la croissance des revenus, il faut s'attendre à de plus importantes mesures de restriction des dépenses.

Le seul secteur où l'on s'attend à une forte croissance cette année, c'est celui du commerce extérieur; mais là aussi la prudence est de mise. Les résultats dont on dispose en matière de commerce sont décevants, les exportations de marchandises accusant une baisse après les cinq premiers mois de l'année. En mai, elles étaient inférieures de 6,7 % par rapport à un an auparavant. Même si le dollar canadien demeure faible (ce qui devrait stimuler le commerce), l'économie américaine a amorcé l'année 2015 au ralenti, le mauvais temps et un conflit de travail dans les ports de la côte Ouest freinant nettement l'activité économique du pays au premier trimestre. Heureusement, l'économie américaine montre déjà des signes de reprise et la hausse de l'activité aux États-Unis d'ici la fin de 2015, puis en 2016, devrait profiter au secteur canadien du commerce extérieur.

En raison de la modeste croissance économique que nous prévoyons, nous croyons que seulement 150 000 emplois s'ajouteront cette année, un bilan de nouveau décevant après celui de 2014, alors que l'embauche fut la plus faible depuis 2009. La croissance de l'emploi devrait s'accélérer en 2016, avec la création de 192 000 postes. Cette année, le taux de chômage grimpera jusqu'à 7 % au quatrième trimestre, puis il redescendra à 6,8 % d'ici la fin de 2016. Même si la conjoncture est moins favorable que ce à quoi nous nous y attendions, nous croyons que la Banque du Canada ne réduira plus les taux d'intérêt après la baisse d'un quart de point de pourcentage annoncée le 15 juillet, et qu'elle commencera à relever les taux vers la fin de 2016, à la faveur d'une économie plus forte. Nous prévoyons une croissance économique de 2,1 % en 2016.

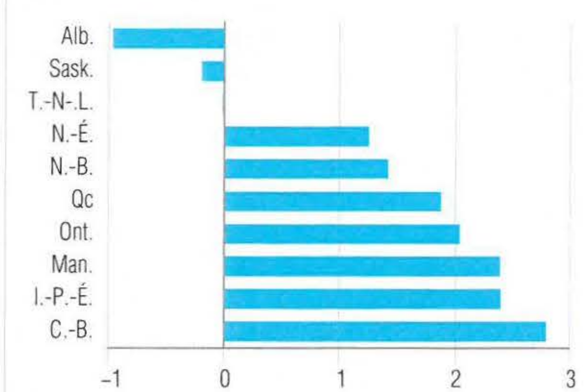
VUE D'ENSEMBLE PROVINCIALE

Alors que l'économie de l'Alberta connaissait des ratés dus au recul des prix du pétrole, tous les yeux et les espoirs se tournaient vers le Canada central, là où un dollar canadien plus faible et l'amélioration de la conjoncture américaine devaient donner de l'élan à l'économie de l'Ontario et du Québec. Mais, après un semestre, les prévisions économiques de presque toutes les provinces ont été revues à la baisse. Le regain économique du Canada central sera moins marqué qu'on l'imaginait, car les exportations n'ont pas évolué au même rythme qu'en 2014. Depuis le début de l'année, divers facteurs, certains temporaires, d'autres plus structuraux, ont nui aux exportateurs du cœur manufacturier canadien.

Les difficultés que connaît le secteur pétrolier auront de sérieux effets sur l'économie de l'Alberta, de la Saskatchewan et de Terre-Neuve-et-Labrador. Et comme un malheur ne vient jamais seul, la sécheresse qui sévit dans l'Ouest nuira aux récoltes, ce qui limitera encore la croissance économique. Si la faiblesse de l'économie canadienne, depuis le début de l'année, découle de la correction dans le secteur de l'énergie, la croissance économique ailleurs que dans l'énergie se fait attendre. Le secteur de l'extraction de minerais métalliques va mal; il est en proie à des turbulences alors que la fin du boom des produits de base entache les perspectives de croissance. La plupart des projets du secteur minier se butent à des problèmes de financement; on en reste souvent au stade de l'élaboration, sans atteindre celui de l'exploitation. C'est même le cas de projets dont la planification est assez avancée. Ce climat a fortement plombé les perspectives du secteur minier pour les prochaines années. En outre, les investissements des entreprises demeurent en général au ralenti dans plusieurs provinces depuis le début de l'année. Certes, la conjoncture économique est loin d'être emballante et ne s'améliore que lentement dans le Canada central et la région de l'Atlantique, mais nous ne croyons pas qu'il en sera ainsi jusqu'à la fin de l'année. En fait, nous prévoyons des résultats économiques plus normaux dans la plupart des provinces dans les mois qui viennent et aussi en 2016, puisque la conjoncture se stabilisera dans l'Ouest canadien et parce que le redressement de l'économie américaine éclairera les perspectives commerciales du Canada central.

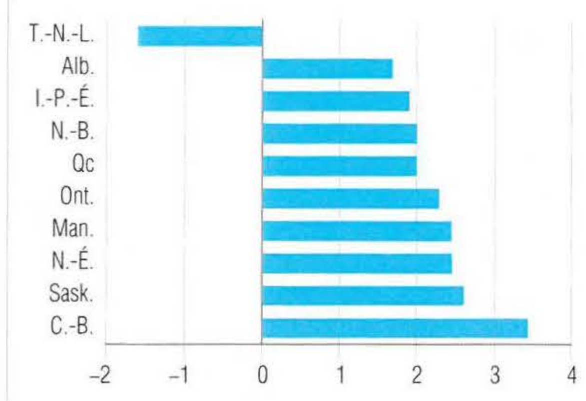
Sur le plan régional, la Colombie-Britannique, le Manitoba, l'Île-du-Prince-Édouard et l'Ontario connaîtront la meilleure croissance du PIB réel cette année, étant les seules provinces à inscrire un gain de 2 % ou plus (voir graphique 1). En 2016, si l'économie du Manitoba se montrera plutôt stable en dépit de conditions plus variables dans le secteur des ressources; c'est la Colombie-Britannique qui affichera la plus forte croissance du PIB réel. De récents développements nous ont amenés à inclure un investissement de grande envergure en C.-B. (un terminal de gaz naturel liquéfié) dans nos prévisions de court terme (voir graphique 2).

Graphique 1
PIB réel des provinces, 2015
(variation en %*)



*dollars de 2007
Sources : Le Conference Board du Canada; Statistique Canada.

Graphique 2
PIB réel des provinces, 2016
(variation en %*)



*dollars de 2007
Sources : Le Conference Board du Canada; Statistique Canada.

HYPOTHÈSES PROVINCIALES

L'économie de Terre-Neuve-et-Labrador est en difficulté. Tous les indicateurs économiques clés sont en baisse pour le premier semestre de 2015 et les faiblesses en cause joueront encore quelques années. Le ralentissement économique s'explique tant par des facteurs cycliques que structuraux. La correction des cours du pétrole, des métaux et des minéraux influe sur les décisions des producteurs et des investisseurs. Et même quand le marché des produits de base prendra du mieux, l'économie mettra du temps à se redresser. Le vieillissement de sa population limitera la capacité de Terre-Neuve-et-Labrador, plus que celle de toute autre province canadienne, à générer une croissance semblable à celle de la dernière décennie. En raison d'un recul de l'emploi, des ventes au détail et des mises en chantier, ainsi que d'une importante correction du marché de la revente, le PIB réel global ne devrait pas progresser du tout en 2015 et il devrait diminuer de 1,6 % en 2016. Certains pans de l'économie progressent rapidement, notamment l'activité manufacturière puisque la transformation a commencé aux installations hydrométallurgiques de Long Harbour.

Si l'économie canadienne est vacillante, celle de l'Île-du-Prince-Édouard semble avancer d'un bon pas même si peu d'emplois y sont créés. En effet, après une forte création d'emplois entre 2010 et 2013 (l'une des meilleures performances au pays), le marché du travail de l'Île s'est figé. Mais l'économie affiche quand même de bons résultats sur plusieurs tableaux, surtout dans le secteur manufacturier et le secteur primaire. De plus, la baisse du dollar canadien devrait aider l'industrie touristique à connaître une belle croissance, un apport qui permettra à l'économie de progresser de 2,4 % en 2015, puis de 1,9 % en 2016.

L'économie de la Nouvelle-Écosse peine à prendre son élan et cette année, la croissance économique y sera moindre que l'an dernier. La nouvelle production de gaz naturel du gisement en mer Deep Panuke d'Encana devait engendrer un essor économique, mais diverses difficultés ont jusqu'ici gêné les opérations et réduit la capacité de production du site. La croissance s'en trouve compromise. Ailleurs que dans l'industrie pétrolière, l'économie semble se solidifier, surtout l'industrie manufacturière et la construction. Mais la province n'est pas parvenue à renverser la tendance négative des deux dernières années dans l'embauche et le marché de l'emploi n'avancera pas encore en 2015. Le ralentissement du secteur de l'énergie dans l'Ouest a probablement un effet défavorable; les travailleurs en affectation par roulement ayant perdu leur poste dans l'Ouest sont en effet inclus dans la main-d'œuvre de leur province d'origine. Quand même, avec le début cet automne des travaux de construction de patrouilleurs pour l'Arctique aux chantiers d'Irving récemment agrandis, la croissance du PIB réel devrait grimper de 1,3 % seulement en 2015 et de 2,5 % en 2016.

Au Nouveau-Brunswick, les perspectives économiques sont modestes, mais bien meilleures que ces dernières années. La reprise du marché de l'emploi est mince sauf que bon nombre de secteurs, comme les fabricants et autres entreprises du secteur forestier notamment, voient le vent souffler dans la bonne direction. Le secteur des services devrait profiter de l'accélération de la production de biens, un phénomène qui relance la création d'emplois et la croissance économique dans l'ensemble. Après des reculs successifs depuis 2011, le PIB réel du Nouveau-Brunswick devrait progresser de 1,4 % cette année, puis de 2 % en 2016.

Les résultats économiques du Québec sont plombés par une importante diminution des exportations. L'économie québécoise aura du mal à s'animer suffisamment en seconde moitié d'année pour que la croissance économique atteigne les 2 %, ou les dépasse. La demande de consommation étant encore assez forte, une croissance économique totale de 1,9 % est prévue pour 2015; il s'agit d'un rendement modeste, mais supérieur à la moyenne nationale d'à peine 1,6 %. Si les exportations devraient s'intensifier au fil des mois, l'industrie aérospatiale se ressentira du recul de la demande à l'égard des jets d'affaires et des milliers de mises à pied annoncées plus tôt cette année chez Bombardier. En 2016, la croissance de l'économie américaine se faisant plus vive, les investissements des entreprises devraient augmenter lentement, évoluant positivement à la fois dans le secteur non résidentiel ainsi que dans le matériel et l'outillage. Divers grands projets devraient se concrétiser dans les années qui viennent, surtout dans le secteur minier, si la conjoncture s'améliore, mais d'ici là les investissements progresseront assez peu dans la province. En 2016, dans l'ensemble, l'économie du Québec évoluera au même rythme que cette année, donc de 2 %, selon nos prévisions. Des restrictions budgétaires limiteront encore les dépenses du gouvernement en matière de programmes et d'infrastructures. En outre, le marché de l'habitation s'affaiblit et ne devrait pas offrir un apport positif au bilan économique.

L'économie ontarienne a connu un lent début d'année. Les exportations ont baissé de 2 % au premier trimestre et semblent bien avoir encore diminué au deuxième trimestre. Les résultats décevants de l'Ontario au tableau du commerce extérieur limiteront sa croissance globale à 2 %, selon les projections. Le gros de la croissance surviendra en seconde moitié d'année. L'élan alors acquis se poursuivra en 2016, année où le PIB réel devrait gagner 2,3 %. Si le secteur du commerce extérieur a rencontré des défis, l'économie intérieure demeure en général forte. La demande des consommateurs évoluera favorablement en réaction à une bonne création d'emplois et à une croissance accrue du revenu disponible des ménages. Le marché de la copropriété de Toronto peut susciter l'inquiétude en raison d'un surplus de construction, mais le secteur de l'habitation (le neuf comme la revente) demeure très fort.

À en juger par la création d'emplois, l'économie du Manitoba est bien en selle : on y prévoit une progression de l'emploi de 1,7 % en 2015, puis de 1,4 % en 2016. Le PIB réel devrait croître de 2,4 % en 2015 et de 2,5 % en 2016, ce qui classera encore la province parmi les leaders au palmarès de la croissance. Des gains constants sont attendus dans l'activité manufacturière, l'agriculture et la construction. Le Manitoba n'est pas soumis aux mêmes pressions que ses voisines, la Saskatchewan et l'Alberta, pour ce qui est de la production agricole.

La Saskatchewan, comme l'Alberta, affichera une évolution négative de son PIB réel cette année. La correction des prix du pétrole a porté un dur coup à l'économie et la sécheresse perturbera le rendement des cultures. Ainsi, le PIB réel devrait reculer de 0,2 % en 2015, mais ce repli pourrait être plus prononcé si les récoltes de blé sont plus touchées qu'on le croyait par les conditions climatiques peu clémentes. Les perspectives économiques devraient être meilleures en 2016, car nous ne prévoyons pas d'autre forte correction dans l'industrie pétrolière. Une bonne progression est aussi prévue dans la production d'uranium et de potasse, de même que dans la construction. Tout compte fait, l'économie de la Saskatchewan devrait inscrire un gain de 2,6 % en 2016.

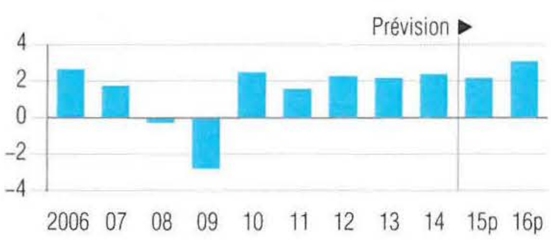
Avec la descente rapide des prix du pétrole brut, des moments douloureux s'annonçaient pour l'économie de l'Alberta; les choses n'ont pas été faciles pour la province depuis le début de l'année. Les activités de soutien à l'exploitation minière et à l'extraction de pétrole et de gaz ont considérablement diminué durant la saison de forage hivernal; les services de forage ont fléchi de quelque 35 %. De plus, les pétrolières ont annoncé des mises à pied et des réductions de leurs plans d'immobilisations dans le secteur énergétique. L'emploi continue de progresser, mais bien moins que ces dernières années. Rien n'est plus difficile à prévoir que les cours des produits de base et il est probable que les prix du pétrole demeureront bas toute l'année prochaine. L'actuel surplus de pétrole constitue encore un facteur clé dans l'établissement des prix du pétrole. Néanmoins, l'économie albertaine devrait se stabiliser un peu en 2016 et nous prévoyons que le PIB réel de la province augmentera de 1,7 % en 2016, après avoir cédé 1 % en 2015.

Du nouveau dans l'industrie du gaz naturel : la Colombie-Britannique vient de légiférer afin de conclure avec Petronas un accord pour construire le terminal d'exportation de GNL Pacific NorthWest, près de Prince Rupert. Ces installations, qui feraient concurrence aux mégaprojets des sables bitumineux de l'Alberta, représenteraient le plus important investissement privé de l'histoire de la province. Si toutes les conditions sont réunies, la construction de ce premier terminal de GNL, un projet de plusieurs milliards de dollars, pourrait s'amorcer en 2016. En même temps, la Colombie-Britannique affiche une bonne croissance économique. Aucune autre province n'offre des perspectives aussi avantageuses. L'économie de la province devrait progresser fortement, soit de 2,8 % en 2015, puis de 3,4 % en 2016. Le marché de l'habitation reste fébrile, tant pour ce qui est des marchés du neuf que de la revente, qui seront en forte hausse cette année. Le marché de l'emploi va bien et les consommateurs devraient faire grimper les ventes au détail de 7,3 % cette année, même si les prix de l'essence ont baissé. L'industrie manufacturière devrait inscrire de bons résultats, tirant profit du regain de l'économie américaine, de la faiblesse du dollar canadien et des travaux de construction de navires non destinés au combat au chantier Seaspan de North Vancouver.

PERSPECTIVES AMÉRICAINES

L'économie américaine a connu des ratés au premier trimestre, ce qui a fait reculer le PIB réel du pays. Heureusement, l'économie s'est ressaisie au trimestre suivant, comme l'indiquent des données encourageantes sur l'emploi pour les mois de mai et du juin. La force du dollar, ainsi que d'autres facteurs, continue toutefois à peser sur la croissance, et ce n'est que maintenant, en deuxième moitié d'année, que la croissance économique s'apprête à atteindre les 3 %. Le faible rendement économique du premier trimestre reportera vraisemblablement la hausse des taux d'intérêt à l'automne, tout dépendant des événements des prochains mois. Nous croyons que le PIB réel gagnera 2,2 % sur l'ensemble de 2015 et 3,1 % en 2016 (voir graphique 3).

Graphique 3
L'économie américaine déçoit, mais les perspectives sont bonnes
(PIB réel des États-Unis; variation en %*)



p = prévision
*en dollars US de 2005
Sources : Le Conference Board du Canada; U.S. Bureau of Economic Analysis (BEA).

Ce fléchissement de l'économie américaine au premier trimestre résulte notamment d'un certain nombre de facteurs temporaires, comme des tempêtes hivernales et une grève (maintenant terminée) d'employés de ports de la côte Ouest, qui ont nui aux exportations. On aurait cependant tort de n'attribuer qu'à des facteurs temporaires cette piètre performance économique, car les investissements dans les projets énergétiques diminuent rapidement et la force du dollar ralentit les exportations et les activités manufacturières.

Au début de cette année, les effets négatifs de la baisse des prix du pétrole et de l'essence ont excédé les aspects positifs pour l'économie américaine. Les investissements réels dans les structures non résidentielles, secteur où se réalisent la majeure partie des investissements relatifs à l'énergie, chutaient de 21 % (taux annuel) au premier trimestre, et on s'attend à un autre repli au deuxième trimestre. Le nombre de puits actifs a reculé de plus de 50 % depuis novembre. Cela illustre comment ce secteur de l'économie est touché par le prix mondial du pétrole, qui se négocie entre 50 et 60 $ US le baril. Cela dit, nous ne prévoyons pas d'autre correction sévère des investissements liés à l'énergie dans la seconde moitié de l'année. Puisque les investissements dans les énergies cesseront de reculer, l'ensemble des investissements dans les constructions non résidentielles devrait croître modérément pendant la seconde moitié de 2015, gagnant 3,2 % en 2016.

La baisse marquée des prix de l'essence aurait pu avoir un effet positif sur les dépenses des ménages, mais cela n'a pas eu lieu, car bon nombre d'entre eux ont plutôt choisi d'épargner davantage. Lorsque le prix de l'essence baisse, il faut toujours attendre un moment avant de voir les Américains dépenser l'argent que cela leur a fait épargner, et c'est ce qui se produit en ce moment. Nous estimons toutefois que les dépenses des ménages augmenteront plus rapidement dans la deuxième moitié de l'année, lorsque ces derniers réagiront finalement aux économies réalisées à la pompe en achetant plus de biens et de services. Les dépenses de consommation réelles devraient progresser de 3,1 % cette année et de 3,3 % l'an prochain.

Le rebond attendu des dépenses des ménages s'observe déjà dans les dernières données sur les ventes de véhicules. En mai, les ventes de voitures ont grimpé à 17,8 millions d'unités (taux annuel désaisonnalisé), par rapport à 16,5 millions en avril. Les gains étaient moindres en juin, mais cela était facile à prévoir vu la flambée du mois de mai. Si une partie des ventes de véhicules est attribuable à l'effet de rattrapage suivant le rude hiver, d'autres facteurs ont motivé les acheteurs. Les marchés de l'emploi s'activent, si bien que les salaires commencent enfin à augmenter de façon significative. Dans les six premiers mois de 2015, c'est bien au-delà de 200 000 emplois qui ont été créés chaque mois, en moyenne. De plus, les créanciers prêtent plus facilement aux emprunteurs plus à risque, tandis que les modalités de financement ont gardé les véhicules à des prix très abordables.

Nous croyons que la Réserve fédérale américaine haussera son taux d'intérêt cet automne, une première depuis 2006, les autorités monétaires estimant alors que l'économie est suffisamment solide pour composer avec des taux plus élevés. Les hausses de taux à venir seront toutefois modestes. Quelques maillons faibles de l'économie, comme le chômage chronique, continuent de préoccuper la Réserve fédérale.

POLITIQUE MONÉTAIRE

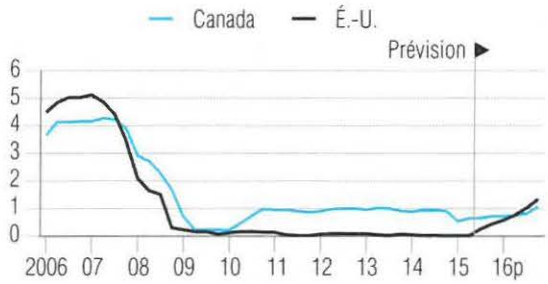
Vu la chute précipitée des cours du pétrole survenue en deuxième moitié de 2014 et au début de 2015, les prix se sont trouvés à augmenter moins qu'un an auparavant dans beaucoup de pays. Mais comme l'effet du recul des prix de l'énergie s'estompe, l'inflation pourrait reprendre. La croissance des prix n'a pas été négative au Canada, mais elle a été limitée depuis le début de l'année par la chute des prix du pétrole. Les variations des prix de l'énergie influent directement sur les composantes « essence et mazout » de l'indice des prix à la consommation (IPC) et indirectement sur l'inflation par leur effet sur la croissance économique. Lorsque la croissance économique est faible, la demande l'est aussi, et c'est ce qui a empêché les prix de monter au début de l'année. À l'opposé, la chute des prix du pétrole a fait perdre de la valeur au huard, ce qui fait augmenter le coût des importations et favorise la progression des prix. Dans l'ensemble, l'inflation totale reste faible, avec une avancée de 1 % en mai, tandis que l'inflation de base a progressé de 2,1 %.

Nous croyons qu'à court terme, l'effet de la hausse des prix à l'importation continuera de combler le manque causé par la faible demande. Ainsi, l'inflation de base restera à au moins 2 % pendant la période prévisionnelle. Mais, outre les répercussions temporaires (comme celles des variations du taux de change), le principal facteur derrière la croissance des prix sera l'écart de production. Cet écart équivaut à la différence entre la production potentielle estimée et la production réelle du Canada; lorsqu'il est négatif, l'économie peut croître au-delà de son potentiel sans exercer de pression inflationniste. La contraction du PIB réel du premier trimestre a creusé cet écart de production, mais lorsque la croissance reprendra dans la deuxième moitié de l'année, l'écart continuera de se refermer et sera de moins de 1 % au début de 2016. La réduction soutenue de l'écart de production entraînera des pressions inflationnistes, mais on s'attend à ce que la Banque du Canada se garde de hausser son taux trop rapidement, pour éviter de nuire à la reprise économique. Selon nos prévisions, les autorités monétaires attendront au moins jusqu'en septembre 2016 pour hausser leurs taux. De plus, la différence entre les politiques de la Banque du Canada (qui a encore baissé son taux directeur d'un quart de point le 15 juillet) et celles de la Réserve fédérale américaine (qui devrait hausser son taux avant la fin de l'année) maintiendra le huard autour des 0,80 $ US jusqu'à la deuxième moitié de 2016 malgré une lente, mais constante remontée du prix du pétrole (voir graphique 4).

PERSPECTIVES BUDGÉTAIRES

Le secteur gouvernemental ne stimulera pas vraiment l'activité économique durant la période de prévision. La plupart des provinces, ainsi que le Canada, espèrent depuis des années vivre un essor économique d'envergure faisant contrepoids à la récession. Mais comme la croissance de la production potentielle du Canada s'effrite en raison du vieillissement de la population et de la rareté des investissements ailleurs que dans le secteur de l'énergie, nous ne prévoyons plus un

Graphique 4
Des taux en hausse aux États-Unis plus tôt que tard
(écart des taux des bons du Trésor américain et canadien à 3 mois en %)



p = prévision
Sources : Le Conference Board du Canada; Banque du Canada.

rebond prononcé de la croissance économique. En fait, la croissance annuelle du PIB réel ne devrait pas dépasser 2,3 % dans les cinq prochaines années. Ce ralentissement de la croissance du PIB limite la progression des revenus du gouvernement et oblige les pouvoirs publics à freiner leurs dépenses afin d'éviter de se retrouver à nouveau en situation déficitaire, ou d'aggraver davantage leurs déficits actuels. Même si les dépenses en biens et services seront faibles, les dépenses publiques totales devraient s'accroître dans les années qui viennent, grâce surtout à une modeste augmentation des investissements dans les infrastructures. Les dépenses publiques réelles de consommation et d'investissement, en déclin l'an dernier, devraient augmenter un peu en 2015, soit de 0,8 %, puis de 0,9 % en 2016.

La plupart des provinces accusent encore des déficits et le gouvernement fédéral ne prévoit que de minces surplus, conditionnels au maintien des restrictions des dépenses. Si le gouvernement fédéral veut atteindre ses cibles budgétaires, il lui faut continuer de limiter sérieusement ses dépenses. Compte tenu de l'inflation, les dépenses fédérales en biens et en services ont diminué durant chacune des quatre dernières années. Des réductions sont attendues encore cette année et en 2016. Ces mesures de restriction devraient permettre au gouvernement fédéral d'afficher de légers surplus (sans tenir compte des fonds pour éventualités) de 2,7 G$ pour l'exercice en cours et de 3,2 G$ pour l'exercice 2016-2017.

Alors que le gouvernement fédéral semble pouvoir composer avec des revenus moindres que ceux prévus sans se retrouver en déficit, les gouvernements des provinces ne jouissent pas d'une situation budgétaire avantageuse et auront du mal à encaisser le coup d'une croissance moins vive. La plupart des provinces ont déposé leurs budgets de 2015 et les perspectives pour l'exercice en cours sont décevantes. Le déficit global des provinces, qui était de 13,7 G$ pour l'exercice 2014-2015, est en voie d'atteindre 15 G$ dans l'exercice en cours. Dans l'avenir prévisible, les provinces feront face à une croissance des revenus inférieure à la moyenne, à une baisse des redevances sur les ressources et à une augmentation de la demande de services financés par elles – un amalgame de facteurs qui les empêchera de renouer avec les surplus dans un avenir rapproché.

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Newfoundland and Labrador

Prince Owusu

Sluggish Economic Outlook Expected For 2015–16

Highlights

- Construction and mining are impeding bottom-line growth over the near term.
- Belt-tightening is ahead for Newfoundland and Labrador consumers as the labour market continues to shed jobs.
- Processing of nickel ore will bolster manufacturing industry growth over the medium term.

Economic Indicators

(percentage change)

	2014	2015f	2016f
Real GDP	−2.9	0.0	−1.6
Consumer Price Index	1.9	0.7	3.3
Household disposable income	3.5	1.4	0.7
Employment	−1.9	−1.3	−0.7
Unemployment rate (level)	12.0	12.6	12.1
Retail sales	3.4	−0.5	1.8
Wages and salaries per employee	6.9	2.8	1.2
Population	−0.2	−0.3	0.0

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

Government and Background Information

Premier	Paul Davis
Next election	October 2015
Population (2015Q2)	525,756
Government balance (2015–16)	−$1.1 billion

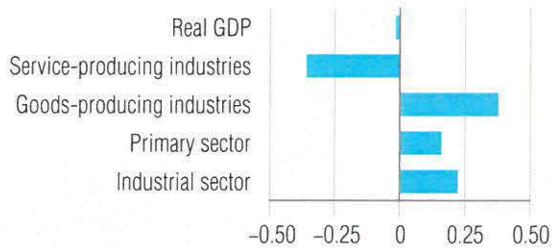
Sources: The Conference Board of Canada; Newfoundland and Labrador Finance.

Newfoundland and Labrador's economy will struggle over the next few years as major projects pass their peak investment levels and current offshore oilfields see production decline. In addition to these project-cycle factors, Newfoundland and Labrador's economy is facing the double whammy of low prices for oil and metals. Brent, the benchmark price for North Sea crude oil by which the province's offshore oil is priced, dropped by more than 50 per cent from its peak last summer, and prices for nickel, copper, and iron ore have all tumbled.

The weak outlook for commodity prices is having a negative impact on near-term investment and production decisions, and this will have a knock-on effect on the labour market and result in weaker economic growth. Real GDP is not expected to grow this year and is forecast to decline by 1.6 per cent in 2016 as investment begins to slow on some of the projects currently under way.

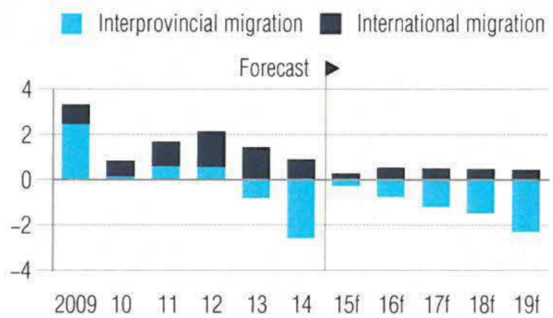
The labour market will continue to feel the effects of the weakening economy. Year-to-date job numbers are down by more than 3,000 for the first half of this year and no reprieve is expected on that front over the medium term as major construction projects unwind. Meanwhile, the spike in the unemployment rate during the first half of this year will not get worse as the labour participation rate is expected to drop. Overall, the unemployment rate will drop from 12.7 per cent in the first half of this year to an average of 12.1 per

Contributions to Newfoundland and Labrador Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



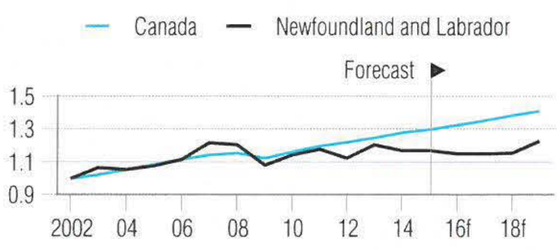
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

cent in 2016 as the number of Newfoundlanders looking for work shrinks. With slack in the labour market, household consumption will be anemic over the next two years and government tax collection from households will be lower. In addition to weaker revenues from households, the provincial government will have to brace for fewer resource royalties for the fiscal year as crude oil and metal prices plummet. This has left the provincial government with a massive $1.1-billion deficit, thereby limiting the government's contribution to bottom-line economic growth.

But, despite this sobering litany of problems, all is not doom and gloom. Manufacturing remains one of the brightest spots in the province's economy. The Long Harbour hydromet facility has begun processing nickel, copper, and cobalt ore from the Voisey's Bay mine and this will help offset some of the weakness in offshore oil production and the construction sector.

CONSTRUCTION OUTLOOK

The construction and mining industries will limit growth prospects in the province over the next four years. Many of the province's major projects have passed peak investment period and will not be contributing to growth. In addition, pressure from low metal commodity prices and difficulty in securing financing are making it more difficult for mining projects to proceed to the development phase. This is especially true for base-metal producers. Overall, real private non-residential investment is forecast to decline by an average of 10 per cent a year throughout the medium term (2015–19), bringing the level of investment to around $5.1 billion in 2019, down from $8.7 billion in 2014.

Residential investment will add to the gloom. With the domestic economy and job market cooling, homebuying activities will not return to the heady pace of the 2008–13 period. Housing starts will drop by 23 per cent this year and by a further 18.6 per cent to reach 1,300 units by next year. In fact, housing starts will continue to fall over the balance of the medium term and, as a result, real residential investment will retreat by an average of 7.5 per cent per year over the medium term.

MINING OUTLOOK

Oil production has been on a downward trajectory since 2008 as the province's offshore production fields have all matured. The downward trend will continue until the newer Hebron offshore field comes on line at the end of 2018. Hebron is currently under development at a cost of $14 billion and will be pumping about 150,000 barrels of oil per day. While the recent drop in crude oil prices has slowed global exploration activities, the impact in Newfoundland and Labrador has not been as bad as in Alberta. In fact, exploration activities at the newly discovered deep-water Flemish Pass Basin are progressing as the major players are keen to integrate Newfoundland and Labrador's offshore industry into the core and strategic part of their business in a race to stake out a piece of the potential there.

On the base-metal front, weaker market conditions over the past year have forced the Wabush and Labrador Iron Mine to close. Low prices have worsened the profit margins of producers in the province at a time when they were already dealing with cost pressures. As a result, some producers are ramping up production to maximize revenues. Tata Steel Minerals Canada (TSMC) is ramping up production at its Elross Lake iron mine while Iron Ore of Canada (IOC) is also boosting production at its mines at the Labrador Trough. The production increases will more than offset output losses from the mines that are shut down; however, output will decline next year as it is not possible to maintain that level of production. Although current market conditions and cost pressures make new mining developments difficult to undertake, we could see few projects developed beyond this year, including Phase II of Vale Inco's Voisey's Bay underground mine. Overall, we expect no growth in real metal mining output over 2015–19.

MANUFACTURING REBOUNDS, THANKS TO BASE METAL

The manufacturing industry is expected to exit the doldrums after contracting by 8.3 per cent last year due to weaker refined petroleum and other non-durable products. The Come by Chance refinery shut down for maintenance and because of unplanned equipment and weather-related outages last year. With the maintenance and outage issues resolved, we anticipate that activities will pick up at the refinery this year. In addition, a lower exchange rate and a revamp of operations at the Corner Brook Pulp and Paper mill (with the help of a $110-million loan from the provincial government) will help bolster the manufacturing industry.

While the industry will continue to benefit from seafood and newsprint production, nickel processing will help lift manufacturing out of the doldrums this year and will continue to support growth going forward. Operations at Vale's nickel processing facility in Long Harbour began in November last year. Production is expected to ramp up over the next three years before reaching full capacity—about 50,000 tonnes of processed nickel per year. This will provide a substantial boost for the manufacturing industry. Overall, a full year of production at Long Harbour will help the manufacturing industry expand by 6.5 per cent in 2015. In 2016, production from the hydromet will still be ramping up, but our forecast is for fabricated metal manufacturing to slow, with overall manufacturing growth coming in at 2.0 per cent.

DOMESTIC DEMAND REMAINS WEAK

The next five years are going to be belt-tightening for Newfoundland and Labrador consumers. The labour market has been hemorrhaging jobs since last year and we expect the losses to continue over the medium term. Investment in most of the province's megaprojects has peaked and workers are losing their jobs. On average, we expect about 1,300 positions to be eliminated each year from now until 2019. Along with weaker demand for labour, workers will see their wages slashed this year as employers try to keep costs down as they face weaker commodity prices. Wages and salaries— the industrial composite—are forecast to drop by 2 per cent this year, the first such decline in a decade after expanding at the breakneck pace of 5.6 per cent per year over 2005–14. Looking ahead, wage growth will be modest beyond next year as labour demand pressures wane.

The job losses have pushed the unemployment rate up to 12.7 per cent for the first half of this year. However, it will not remain there for long as the shrinking of the province's labour force will pull the rate down to around 12.1 per cent by next year. The slide in the unemployment rate will then continue through to 2019. The job losses, combined with lower wages, will dampen consumer spending over the next two years. Real household consumption expenditures will decline by an average of 0.4 per cent over 2015–16. Given the weak demand outlook, we expect overall consumer price inflation to average a tame 0.7 per cent this year, well below the Bank of Canada's mid-range target of 2 per cent. But consumer price inflation will shoot back up to 3.3 per cent next year with the 2 percentage point increase in the provincial sales tax, for an HST rate of 15 per cent.

Forecast Risks

Short term

- Further depreciation of the Canadian dollar should provide some upside risks for manufacturers in the province.

Medium term

- If owners of the West White Rose Extension change plans and decide to accelerate the development, it could provide relief for struggling construction workers.

Source: The Conference Board of Canada.

Key Economic Indicators: Newfoundland and Labrador

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	36,115	35,696	35,170	32,309	33,221	32,852	32,892	33,038	33,744	33,991	34,193	34,245	34,823	33,001	34,043
	1.7	*−1.2*	*−1.5*	*−8.1*	*2.8*	*−1.1*	*0.1*	*0.4*	*2.1*	*0.7*	*0.6*	*0.2*	*−2.8*	*−5.2*	*3.2*
GDP at market prices (2007 $ millions)	29,043	28,657	28,301	28,961	29,008	28,657	28,605	28,548	28,305	28,235	28,215	28,141	28,740	28,704	28,224
	−2.0	*−1.3*	*−1.2*	*2.3*	*0.2*	*−1.2*	*−0.2*	*−0.2*	*−0.9*	*−0.2*	*−0.1*	*−0.3*	*−2.9*	*−0.1*	*−1.7*
GDP at basic prices (2007 $ millions)	27,207	26,846	26,512	27,130	27,194	26,872	26,829	26,781	26,548	26,490	26,482	26,426	26,924	26,919	26,486
	−2.0	*−1.3*	*−1.2*	*2.3*	*0.2*	*−1.2*	*−0.2*	*−0.2*	*−0.9*	*−0.2*	*0.0*	*−0.2*	*−2.9*	*0.0*	*−1.6*
Consumer price index (2002 = 1.0)	1.276	1.290	1.290	1.279	1.275	1.291	1.299	1.304	1.326	1.333	1.339	1.343	1.284	1.292	1.335
	0.6	*1.1*	*0.0*	*−0.9*	*−0.3*	*1.2*	*0.6*	*0.4*	*1.7*	*0.5*	*0.5*	*0.3*	*1.9*	*0.7*	*3.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.244	1.246	1.243	1.116	1.145	1.146	1.150	1.157	1.192	1.204	1.212	1.217	1.212	1.150	1.206
	3.8	*0.2*	*−0.2*	*−10.2*	*2.7*	*0.1*	*0.3*	*0.6*	*3.0*	*1.0*	*0.7*	*0.4*	*0.1*	*−5.1*	*4.9*
Wages and salary per employee ($ 000s)	50.102	51.685	51.886	52.130	53.087	52.817	52.690	53.028	53.212	53.422	53.640	53.848	51.451	52.905	53.531
	0.9	*3.2*	*0.4*	*0.5*	*1.8*	*−0.5*	*−0.2*	*0.6*	*0.3*	*0.4*	*0.4*	*0.4*	*6.9*	*2.8*	*1.2*
Primary household income ($ millions)	18,248	18,368	18,516	18,655	18,836	18,680	18,679	18,793	18,884	18,902	18,953	19,031	18,447	18,747	18,943
	0.1	*0.7*	*0.8*	*0.8*	*1.0*	*−0.8*	*0.0*	*0.6*	*0.5*	*0.1*	*0.3*	*0.4*	*4.1*	*1.6*	*1.0*
Household disposable income ($ millions)	17,138	17,188	17,356	17,407	17,561	17,442	17,520	17,517	17,571	17,596	17,642	17,716	17,272	17,510	17,631
	−0.5	*0.3*	*1.0*	*0.3*	*0.9*	*−0.7*	*0.4*	*0.0*	*0.3*	*0.1*	*0.3*	*0.4*	*3.5*	*1.4*	*0.7*
Household net savings rate (per cent)	9.4	8.5	8.3	8.5	10.5	9.1	9.2	8.7	8.5	8.5	8.5	8.5	8.7	9.4	8.5
Population (000s)	528	527	527	527	526	526	525	525	526	526	526	526	527	526	526
	−0.1	*−0.3*	*0.0*	*0.0*	*−0.1*	*−0.1*	*−0.1*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*−0.2*	*−0.3*	*0.0*
Employment (000s)	242	236	237	238	236	236	235	235	235	234	233	233	238	235	234
	−0.6	*−2.1*	*0.5*	*0.4*	*−1.0*	*−0.1*	*−0.2*	*−0.1*	*−0.1*	*−0.4*	*−0.2*	*0.0*	*−1.9*	*−1.3*	*−0.7*
Labour force (000s)	274	269	271	270	269	271	269	268	268	266	265	265	271	269	266
	−0.3	*−1.9*	*0.7*	*−0.4*	*−0.1*	*0.4*	*−0.5*	*−0.3*	*−0.3*	*−0.5*	*−0.4*	*−0.1*	*−1.4*	*−0.5*	*−1.3*
Labour force participation rate (per cent)	61.6	60.6	61.0	60.8	60.8	61.1	60.8	60.7	60.5	60.2	60.0	59.9	61.0	60.8	60.1
Unemployment rate (per cent)	11.9	12.1	12.3	11.6	12.4	12.9	12.6	12.5	12.2	12.2	12.0	11.9	12.0	12.6	12.1
Retail sales ($ millions)	8,737	8,841	9,022	8,926	8,708	8,842	8,860	8,930	8,970	8,979	9,000	9,029	8,881	8,835	8,994
	1.9	*1.2*	*2.0*	*−1.1*	*−2.4*	*1.5*	*0.2*	*0.8*	*0.4*	*0.1*	*0.2*	*0.3*	*3.4*	*−0.5*	*1.8*
Housing starts (units, 000s)	2,148	2,147	2,208	1,973	2,204	1,515	1,412	1,397	1,369	1,342	1,315	1,289	2,119	1,632	1,329
	−32.4	*0.0*	*2.8*	*−10.6*	*11.7*	*−31.3*	*−6.8*	*−1.0*	*−2.0*	*−2.0*	*−2.0*	*−2.0*	*−26.0*	*−23.0*	*−18.6*
Net interprovincial migration (000s)	−3.9	−2.3	−2.6	−1.5	−0.9	−0.1	−0.1	−0.1	−0.6	−0.8	−0.8	−0.9	−2.6	−0.3	−0.7
Net international migration (000s)	−0.9	2.1	2.4	0.0	−0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.9	0.3	0.5

Shaded 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: Newfoundland and Labrador cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	34,161	34,265	34,376	34,461	34,359	34,692	35,141	35,622	36,413	37,345	38,382	39,491	34,316	34,953	37,908
	-0.2	*0.3*	*0.3*	*0.2*	*-0.3*	*1.0*	*1.3*	*1.4*	*2.2*	*2.6*	*2.8*	*2.9*	*0.8*	*1.9*	*8.5*
GDP at market prices (2007 $ millions)	28,113	28,068	28,068	28,086	27,859	27,977	28,201	28,543	28,986	29,543	30,200	30,959	28,084	28,145	29,922
	-0.1	*-0.2*	*0.0*	*0.1*	*-0.8*	*0.4*	*0.8*	*1.2*	*1.6*	*1.9*	*2.2*	*2.5*	*-0.5*	*0.2*	*6.3*
GDP at basic prices (2007 $ millions)	26,424	26,399	26,416	26,450	26,261	26,386	26,609	26,938	27,361	27,886	28,504	29,215	26,422	26,549	28,242
	0.0	*-0.1*	*0.1*	*0.1*	*-0.7*	*0.5*	*0.8*	*1.2*	*1.6*	*1.9*	*2.2*	*2.5*	*-0.2*	*0.5*	*6.4*
Consumer price index (2002 = 1.0)	1.351	1.361	1.367	1.371	1.379	1.388	1.395	1.399	1.407	1.417	1.424	1.428	1.362	1.391	1.419
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.0*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.215	1.221	1.225	1.227	1.233	1.240	1.246	1.248	1.256	1.264	1.271	1.276	1.222	1.242	1.267
	-0.1	*0.5*	*0.3*	*0.2*	*0.5*	*0.5*	*0.5*	*0.2*	*0.7*	*0.6*	*0.5*	*0.4*	*1.3*	*1.6*	*2.0*
Wages and salary per employee ($ 000s)	54.345	54.605	54.916	55.360	55.767	56.356	56.802	57.210	57.594	57.920	58.311	58.686	54.806	56.534	58.128
	0.9	*0.5*	*0.6*	*0.8*	*0.7*	*1.1*	*0.8*	*0.7*	*0.7*	*0.6*	*0.7*	*0.6*	*2.4*	*3.2*	*2.8*
Primary household income ($ millions)	19,177	19,273	19,385	19,502	19,658	19,832	19,968	20,096	20,278	20,377	20,484	20,583	19,335	19,889	20,430
	0.8	*0.5*	*0.6*	*0.6*	*0.8*	*0.9*	*0.7*	*0.6*	*0.9*	*0.5*	*0.5*	*0.5*	*2.1*	*2.9*	*2.7*
Household disposable income ($ millions)	17,895	17,985	18,086	18,189	18,317	18,463	18,574	18,687	18,848	18,947	19,045	19,126	18,039	18,510	18,991
	1.0	*0.5*	*0.6*	*0.6*	*0.7*	*0.8*	*0.6*	*0.6*	*0.9*	*0.5*	*0.5*	*0.4*	*2.3*	*2.6*	*2.6*
Household net savings rate (per cent)	8.7	8.8	8.8	8.7	8.7	8.7	8.8	8.8	8.8	8.9	9.0	9.1	8.7	8.8	8.9
Population (000s)	526	526	525	525	525	525	524	524	525	525	525	525	525	525	525
	0.0	*0.0*	*0.0*	*0.0*	*-0.1*	*-0.1*	*0.0*	*0.0*	*0.2*	*0.0*	*0.0*	*-0.1*	*-0.1*	*-0.2*	*0.1*
Employment (000s)	234	233	233	233	232	232	232	232	232	232	232	232	233	232	232
	0.1	*-0.1*	*-0.1*	*-0.3*	*-0.1*	*-0.1*	*-0.1*	*-0.1*	*0.2*	*0.0*	*-0.1*	*-0.1*	*-0.3*	*-0.5*	*0.0*
Labour force (000s)	265	265	264	263	263	262	261	260	260	260	260	259	264	261	260
	0.0	*-0.1*	*-0.1*	*-0.3*	*-0.3*	*-0.4*	*-0.4*	*-0.1*	*0.0*	*-0.1*	*-0.2*	*-0.3*	*-0.6*	*-1.1*	*-0.6*
Labour force participation rate (per cent)	60.0	59.9	59.9	59.7	59.6	59.4	59.3	59.2	59.1	59.1	59.0	58.9	59.9	59.4	59.0
Unemployment rate (per cent)	11.8	11.8	11.7	11.7	11.6	11.3	11.0	11.0	10.8	10.8	10.7	10.6	11.8	11.2	10.7
Retail sales ($ millions)	9,103	9,138	9,186	9,244	9,321	9,400	9,457	9,518	9,600	9,642	9,690	9,725	9,168	9,424	9,665
	0.8	*0.4*	*0.5*	*0.6*	*0.8*	*0.9*	*0.6*	*0.6*	*0.9*	*0.4*	*0.5*	*0.4*	*1.9*	*2.8*	*2.6*
Housing starts (units, 000s)	1,263	1,238	1,213	1,189	1,165	1,142	1,120	1,097	1,076	1,054	1,033	1,013	1,226	1,131	1,044
	-2.0	*-2.0*	*-2.0*	*-2.0*	*-2.0*	*-2.0*	*-2.0*	*-2.0*	*-1.9*	*-2.0*	*-2.0*	*-2.0*	*-7.8*	*-7.7*	*-7.7*
Net interprovincial migration (000s)	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-1.6	-1.7	-1.9	-2.1	-2.5	-2.7	-1.2	-1.5	-2.3
Net international migration (000s)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Shaded 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

Daniel Fields

Good Times on the Island

Highlights

- Solid export growth is expected over the near term.
- Construction will be a major player in the province in 2015 and 2016.
- The government delayed its balanced-budget target by one year to 2016–17.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.3	2.4	1.9
Consumer Price Index	1.6	–0.1	2.3
Household disposable income	1.9	1.5	2.5
Employment	–0.4	–0.5	1.0
Unemployment rate (level)	10.5	10.5	10.0
Retail sales	3.3	0.6	3.8
Wages and salaries per employee	2.1	1.0	2.1
Population	0.4	0.3	0.5

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

Government and Background Information

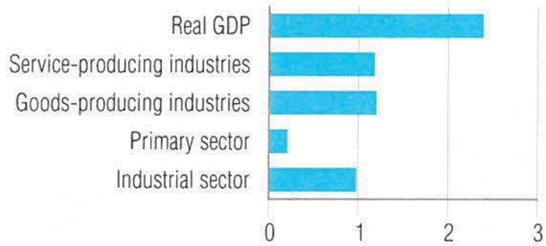
Premier	Wade MacLauchlan
Next election	2015
Population (2015Q2)	146,293
Government balance (2015–16)	–$19.9 million

Sources: The Conference Board of Canada; Prince Edward Island Finance.

Prince Edward Island has finally thawed out after its record-breaking, snow-filled winter and is back on track to being one of Canada's leaders in economic growth for 2015. Thanks to the one-two punch of construction and manufacturing, as well as a surging export sector, the Island possesses solid economic prospects this year and next. The past winter saw a record amount of snowfall that postponed the opening of lobster season; however, despite the winter setback, the fishing industry is still expected to perform well this year, thanks to strong demand for lobster from China. In general, the Island's export sector will be a major positive for the province due mainly to a booming U.S. economy and the weaker Canadian dollar. As well, there are healthy building construction intentions for 2015 and that, combined with a surge in housing starts next year, will support the construction sector over the near term. All these signs point to a healthy economy over the next two years on the Island, putting the province ahead of the national average. In particular, real GDP is expected to grow by 2.4 per cent this year and 1.9 per cent in 2016.

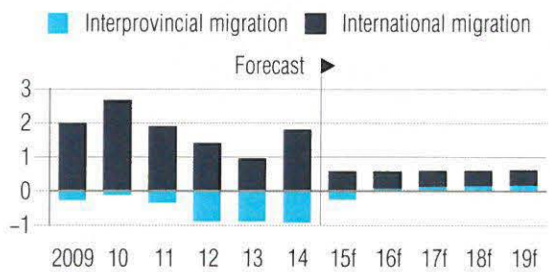
The recently re-elected Liberal government released its annual budget on June 19 and, as expected, the province continued its mandate of controlled spending. Despite the frugality, the province had to delay its target for a balanced budget by one year to 2016–17. Tight spending measures translate into weak growth in

Contributions to Prince Edward Island Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



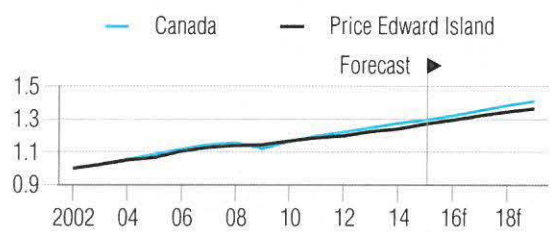
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

non-commercial services such as education and health and social services, which puts a damper on overall economic growth. This makes the positive economic outlook for the Island that much more impressive. With the combination of a strong economy and tighter spending, the province should certainly achieve its new fiscal-balance goal for 2016–17.

CONSTRUCTION AND MANUFACTURING BIG PLAYERS IN ISLAND GROWTH

The construction industry is one of the main reasons why economic growth on the Island is forecast to be strong this year and next. Real output in construction is set to rise by 9 per cent this year, thanks to robust building intentions in non-residential construction. Not to be left out, residential investment is also a healthy part of the increase in construction, growing by 19 per cent this year and 11 per cent next year in real terms. Housing starts are a big part of this increase in investment and are expected to rise next year by an impressive 23 per cent.

Manufacturing is set to grow at a more reasonable pace over the near term. The stronger U.S. dollar continues to drive up demand for P.E.I. products. Growth in the manufacturing sector should hit nearly 4 per cent this year, backed largely by a solid performance by aerospace and pharmaceutical products. Over the near term, manufacturing growth will fall back to the 2.5 per cent range as the sector is held back somewhat by modest advances in agriculture and by weakness in the fishing industry.

NEAR-TERM PROSPECTS WEAK FOR PRIMARY SECTOR

The industry got off to a slow start this year because of the poor winter weather that delayed the start of lobster season. However, as the ice thawed, so too did the fishing sector. Overall, thanks to strong demand from China, fishing and trapping should see growth of nearly 7 per cent this year. Growth in this industry goes a long way in improving the Island's primary sector, as fishing and trapping make up nearly one-third of the overall segment. With that in mind, however, the fishing sector may struggle over the near term as the industry adjusts to new labour restrictions on temporary foreign workers, a crucial input of the seasonal lobster catch. Next year, real growth in the fishing sector is expected to see a small decline.

Slow growth is anticipated in the agriculture industry over the near term as well. The industry, which makes up about two-thirds of the primary sector or about 4.5 per cent of the Island's economy, is forecast to expand by 1.7 per cent this year and 0.5 per cent next year. Increased production of potatoes in Texas is exerting downward pressure on prices and hampering the Island's agriculture prospects. Additionally, allegations of tampering with Island potatoes have raised concerns over the Island's staple product. Partially making up for this shrinking demand for potatoes is blueberry production that hit an all-time high in 2014 and should continue to be a strong source of growth for the agriculture industry. As well, other products such as barley and soybeans should continue to see production gains. However, these crops are unlikely to fill the hole left by the potato market, making overall agricultural prospects weak over the near term with average annual growth of around 1 per cent.

TOURISM IN FOR A GOOD YEAR

Last year, 2014, was a great year for tourism to the Island as the province celebrated the 150th anniversary of the Charlottetown Conference with many special events. Typically, after a once-in-a-lifetime celebration, we would expect to see a drop-off in the number of overnight visitors the following year. And, while this will still likely be the case this year, especially for domestic visitors (due to the weakness in most other provincial economies), visitors from the United States should pick up the slack thanks to robust economic growth. (More details can be seen in the Conference Board's *Travel Markets Outlook – National Focus: Spring 2015*.)

EMPLOYMENT PROSPECTS WILL IMPROVE NEXT YEAR

It has been a slow start for employment on the Island. While the second half of the year should be better for job creation, overall employment is forecast to decline by 0.5 per cent this year. This is not surprising when you consider the closure of the retail giant Target, which announced it was shutting its Charlottetown store in early 2015. The closure affected over 100 P.E.I. workers and will weigh on the year in terms of overall job growth. As well, employment growth had been exceptionally strong between 2010 and 2013 so a slowdown is not worrisome.

Next year is looking better for employment prospects on the Island. Very healthy growth in construction and manufacturing should provide plenty of work for those currently unemployed. This improvement in employment (as well as more people retiring out of the labour force) should lead to the unemployment rate falling to 10 per cent next year, which would mark the lowest level since 1978. The pickup in employment will also help boost household disposable income by 2.9 per cent next year, which will support real growth in household consumer expenditures of 2 per cent in 2016. This is good news for retailers on the Island; retail sales are forecast to gain 3.8 per cent as a result.

GOVERNMENT STILL WORKING TOWARD A BALANCED BUDGET

The P.E.I. government continues to work toward balancing its budget—an especially difficult task in a province that has posted a surplus budget in only 2 of last 14 fiscal years since 2000–01. The recently tabled provincial budget still calls for expenditure restraint to eliminate the deficit, but the province had to push out its target for balancing the budget by one fiscal year to 2016–17 with nominal program expenditures expected to decline this fiscal year. As the government holds the line on spending increases, there will be little contribution from the public sector to economic growth, which makes the positive economic outlook for the province that much more impressive.

Forecast Risks

Short term

- Weaker economic times in other provinces may reduce the number of domestic visitors to the Island more than expected.

Medium term

- Changes to the Temporary Foreign Workers Program should improve employment prospects and strengthen wage growth, as employers are forced to adjust to the new restrictions and fill more jobs locally.

Source: The Conference Board of Canada.

Key Economic Indicators: Prince Edward Island

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	5,827	5,854	6,001	6,200	6,102	6,197	6,289	6,352	6,381	6,443	6,514	6,563	5,971	6,235	6,475
	1.8	*0.5*	*2.5*	*3.3*	*–1.6*	*1.6*	*1.5*	*1.0*	*0.5*	*1.0*	*1.1*	*0.7*	*3.2*	*4.4*	*3.9*
GDP at market prices (2007 $ millions)	4,974	4,983	5,090	5,233	5,158	5,172	5,205	5,229	5,247	5,273	5,310	5,331	5,070	5,191	5,290
	–0.3	*0.2*	*2.1*	*2.8*	*–1.4*	*0.3*	*0.6*	*0.5*	*0.3*	*0.5*	*0.7*	*0.4*	*1.3*	*2.4*	*1.9*
GDP at basic prices (2007 $ millions)	4,556	4,564	4,662	4,793	4,724	4,737	4,767	4,790	4,806	4,830	4,863	4,883	4,644	4,755	4,845
	–0.3	*0.2*	*2.1*	*2.8*	*–1.4*	*0.3*	*0.6*	*0.5*	*0.3*	*0.5*	*0.7*	*0.4*	*1.3*	*2.4*	*1.9*
Consumer price index (2002 = 1.0)	1.301	1.305	1.304	1.293	1.282	1.297	1.305	1.310	1.318	1.327	1.333	1.338	1.301	1.299	1.329
	0.9	*0.4*	*–0.1*	*–0.8*	*–0.8*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.6*	*–0.1*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.171	1.175	1.179	1.185	1.183	1.198	1.208	1.215	1.216	1.222	1.227	1.231	1.178	1.201	1.224
	2.0	*0.3*	*0.4*	*0.5*	*–0.2*	*1.3*	*0.8*	*0.5*	*0.1*	*0.5*	*0.4*	*0.4*	*1.8*	*2.0*	*1.9*
Wages and salary per employee ($ 000s)	34.630	34.940	34.758	34.929	34.910	35.091	35.296	35.411	35.616	35.782	35.998	36.203	34.814	35.177	35.900
	0.6	*0.9*	*–0.5*	*0.5*	*–0.1*	*0.5*	*0.6*	*0.3*	*0.6*	*0.5*	*0.6*	*0.6*	*2.1*	*1.0*	*2.1*
Primary household income ($ millions)	4,078	4,087	4,101	4,123	4,151	4,114	4,170	4,202	4,236	4,263	4,296	4,329	4,097	4,159	4,281
	1.0	*0.2*	*0.3*	*0.5*	*0.7*	*–0.9*	*1.4*	*0.8*	*0.8*	*0.6*	*0.8*	*0.8*	*2.0*	*1.5*	*2.9*
Household disposable income ($ millions)	3,908	3,910	3,922	3,936	3,966	3,933	4,007	4,010	4,035	4,061	4,092	4,121	3,919	3,979	4,077
	0.9	*0.1*	*0.3*	*0.4*	*0.8*	*–0.8*	*1.9*	*0.1*	*0.6*	*0.6*	*0.8*	*0.7*	*1.9*	*1.5*	*2.5*
Household net savings rate (per cent)	–3.3	–5.4	–6.5	–5.0	–3.4	–5.5	–5.3	–6.0	–6.2	–6.2	–6.2	–6.1	–5.1	–5.1	–6.2
Population (000s)	145	146	146	147	146	146	147	147	147	147	147	148	146	146	147
	0.0	*0.2*	*0.3*	*0.2*	*0.0*	*–0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.4*	*0.3*	*0.5*
Employment (000s)	74	73	74	74	74	73	74	74	74	74	74	75	74	74	74
	0.3	*–0.7*	*1.0*	*–0.3*	*0.0*	*–1.4*	*0.9*	*0.4*	*0.3*	*0.2*	*0.2*	*0.2*	*–0.4*	*–0.5*	*1.0*
Labour force (000s)	83	83	82	82	83	82	82	82	82	83	83	83	83	82	83
	–0.3	*–0.5*	*–1.0*	*0.6*	*0.2*	*–0.9*	*0.5*	*0.2*	*0.1*	*0.1*	*0.2*	*0.1*	*–1.5*	*–0.4*	*0.4*
Labour force participation rate (per cent)	69.0	68.6	67.9	68.3	68.4	67.7	68.1	68.2	68.1	68.1	68.2	68.1	68.5	68.1	68.1
Unemployment rate (per cent)	11.1	11.2	9.4	10.2	10.5	10.9	10.5	10.3	10.2	10.0	10.0	9.8	10.5	10.5	10.0
Retail sales ($ millions)	1,954	2,004	2,058	2,004	1,961	2,006	2,043	2,060	2,075	2,087	2,101	2,112	2,005	2,017	2,094
	0.8	*2.5*	*2.7*	*–2.6*	*–2.2*	*2.3*	*1.8*	*0.8*	*0.7*	*0.6*	*0.7*	*0.5*	*3.3*	*0.6*	*3.8*
Housing starts (units, 000s)	409	649	381	605	620	357	518	571	629	631	638	646	511	517	636
	–5.6	*58.9*	*–41.3*	*58.7*	*2.5*	*–42.4*	*45.1*	*10.3*	*10.1*	*0.3*	*1.1*	*1.3*	*–19.7*	*1.1*	*23.2*
Net interprovincial migration (000s)	–0.1	–1.0	–2.1	–0.6	–1.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	–0.9	–0.3	0.1
Net international migration (000s)	1.5	2.8	2.8	0.2	0.7	0.7	0.5	0.5	0.5	0.5	0.5	0.5	1.8	0.6	0.5

Shaded 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: Prince Edward Island cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	6,646	6,712	6,774	6,826	6,901	6,966	7,025	7,060	7,122	7,180	7,230	7,263	6,739	6,988	7,199
	1.3	*1.0*	*0.9*	*0.8*	*1.1*	*0.9*	*0.8*	*0.5*	*0.9*	*0.8*	*0.7*	*0.5*	*4.1*	*3.7*	*3.0*
GDP at market prices (2007 $ millions)	5,368	5,389	5,415	5,442	5,467	5,486	5,506	5,526	5,543	5,559	5,575	5,590	5,403	5,496	5,567
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.1*	*1.7*	*1.3*
GDP at basic prices (2007 $ millions)	4,916	4,935	4,960	4,984	5,007	5,025	5,043	5,062	5,077	5,092	5,106	5,120	4,949	5,034	5,099
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.1*	*1.7*	*1.3*
Consumer price index (2002 = 1.0)	1.346	1.355	1.362	1.366	1.374	1.383	1.390	1.394	1.402	1.412	1.419	1.423	1.357	1.385	1.414
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.238	1.246	1.251	1.254	1.262	1.270	1.276	1.277	1.285	1.292	1.297	1.299	1.247	1.271	1.293
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.7*
Wages and salary per employee ($ 000s)	36.415	36.615	36.807	37.046	37.287	37.548	37.782	38.005	38.220	38.443	38.673	38.891	36.721	37.656	38.557
	0.6	*0.5*	*0.5*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*2.3*	*2.5*	*2.4*
Primary household income ($ millions)	4,362	4,402	4,435	4,471	4,512	4,553	4,585	4,616	4,652	4,680	4,710	4,738	4,418	4,566	4,695
	0.8	*0.9*	*0.7*	*0.8*	*0.9*	*0.9*	*0.7*	*0.7*	*0.8*	*0.6*	*0.6*	*0.6*	*3.2*	*3.4*	*2.8*
Household disposable income ($ millions)	4,165	4,199	4,227	4,260	4,298	4,337	4,368	4,398	4,433	4,463	4,492	4,520	4,213	4,350	4,477
	1.1	*0.8*	*0.7*	*0.8*	*0.9*	*0.9*	*0.7*	*0.7*	*0.8*	*0.7*	*0.7*	*0.6*	*3.3*	*3.3*	*2.9*
Household net savings rate (per cent)	-5.9	-5.8	-5.8	-5.9	-5.9	-5.8	-5.8	-5.8	-5.7	-5.6	-5.5	-5.4	-5.9	-5.8	-5.6
Population (000s)	148	148	148	148	149	149	149	149	149	150	150	150	148	149	150
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.6*	*0.6*	*0.5*
Employment (000s)	75	75	75	75	76	76	76	76	76	76	76	76	75	76	76
	0.3	*0.4*	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*1.1*	*0.8*	*0.4*
Labour force (000s)	83	83	83	83	83	83	84	84	84	84	84	84	83	84	84
	0.2	*0.1*	*0.0*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.5*	*0.6*	*0.4*
Labour force participation rate (per cent)	68.2	68.2	68.1	68.1	68.2	68.3	68.2	68.2	68.2	68.2	68.1	68.1	68.2	68.2	68.1
Unemployment rate (per cent)	9.8	9.5	9.4	9.4	9.4	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.5	9.3	9.3
Retail sales ($ millions)	2,127	2,140	2,149	2,164	2,182	2,199	2,211	2,223	2,236	2,246	2,256	2,265	2,145	2,204	2,251
	0.7	*0.6*	*0.4*	*0.7*	*0.8*	*0.8*	*0.5*	*0.5*	*0.6*	*0.4*	*0.5*	*0.4*	*2.5*	*2.7*	*2.1*
Housing starts (units, 000s)	643	640	651	658	654	639	638	634	614	601	608	612	648	641	609
	-0.5	*-0.4*	*1.7*	*1.1*	*-0.6*	*-2.4*	*-0.1*	*-0.6*	*-3.2*	*-2.1*	*1.3*	*0.7*	*1.9*	*-1.1*	*-5.1*
Net interprovincial migration (000s)	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Net international migration (000s)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5

Shaded 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.

Natalia Ward

Natural Gas Production Weighs Down GDP Growth in 2015

Highlights

- The outlook for natural gas production in Nova Scotia is bleak.
- Both manufacturing and construction will see strong gains over the near term.
- Healthy growth in the goods-producing sector will bring a recovery in job creation next year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.6	1.3	2.5
Consumer Price Index	1.7	0.6	2.3
Household disposable income	2.4	2.2	2.5
Employment	–1.1	–0.1	1.0
Unemployment rate (level)	8.9	8.7	8.5
Retail sales	2.3	–1.6	4.1
Wages and salaries per employee	3.4	1.7	1.8
Population	0.0	0.0	0.2

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

Government and Background Information

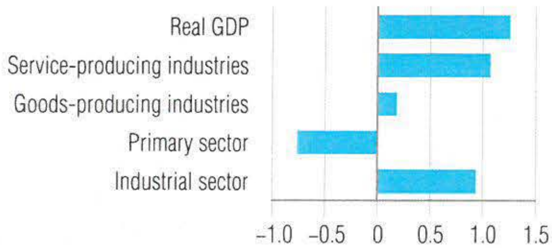
Premier	Stephen McNeil
Next election	2019
Population (2015Q2)	942,926
Government balance (2015–16)	–$97.6 million

Sources: The Conference Board of Canada; Nova Scotia Budget Documents.

After modest economic growth this year, Nova Scotia's economy is forecast to post robust growth in 2016. Real GDP is expected to increase 1.3 per cent in 2015 and 2.5 per cent in 2016. Over the near term, declines in natural gas production will take away from bottom-line growth in the province. Production at the mature Sable Island Energy Project (SOEP) will continue to decline. ExxonMobil Canada indicated that the five fields of the project will stop producing natural gas as early as 2017 and the field will be decommissioned. In addition, Encana's Deep Panuke offshore project will now become a seasonal operation and is expected to produce natural gas for only another three years.

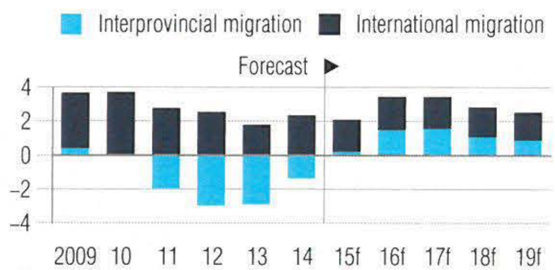
Despite a rather bleak outlook for mineral fuels mining, the other goods-producing industries will perform well; manufacturing and construction should post strong growth this year and next. Manufacturing will be supported by the Irving shipbuilding contract that is expected to begin in the fall of this year. In addition, other manufacturing sectors are aiming to expand their production in the province. Construction will rebound this year and see double-digit growth this year and next. Work on the Nova Centre and on King's Wharf projects in Halifax, the Maritime Transmission Link Project, and wind power expansion will keep construction workers busy in the province.

Contributions to Nova Scotia Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



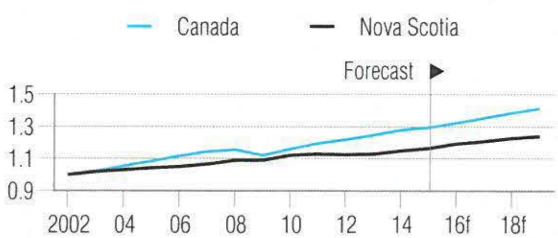
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

Employment will see another disappointing year in 2015. Over the first six months of the year, total employment fell and, although it is projected to recover somewhat in the remainder of the year, it will not be enough to offset the losses from the beginning of the year. Next year promises better employment prospects; after a 0.1 per cent decline in 2015, employment will rebound with 1 per cent growth in 2016.

NATURAL GAS PROSPECTS

The outlook for natural gas production in Nova Scotia is not that good at the moment. Production at Deep Panuke offshore gas field this past winter was well below last year's levels; the field produced an average of 170 million cubic feet per day from November to March—about 50 million cubic feet fewer than the same period last year. Deep Panuke is expected to produce for only another three years and then only on a seasonal basis.

ExxonMobil will be calling for bids on work to plug wells at the SOEP; however, it may take a year before a timeline is in place to determine when the five fields will stop producing.

The Nova Scotia government has already begun planning for the end of operations at Sable Island and for the end of the royalties it provides to the province. A portion of the decommissioning costs incurred by ExxonMobil and its partners would be deducted from previous royalties paid. SOEP royalties account for a good portion of the $1.9 billion that Nova Scotia has collected from offshore energy.

All told, mineral fuels output will fall by 37.1 per cent in 2015 and another 14 per cent in 2016.

CONSTRUCTION AND MANUFACTURING DOING WELL

Both manufacturing and construction will see strong gains over the near term. Construction will be supported by a number of large-scale projects, including the $500-million Nova Centre in downtown Halifax and the King's Wharf project. These developments will include a convention centre, office towers, luxury hotels, retail outlets, restaurants, and a residential complex. The Maritime Transmission Link Project and wind power expansion projects will also help propel growth in business non-residential investment. In addition, Shell and BP will spend more than $2 billion over the next six years on exploration in Nova Scotia's offshore. Residential investment will also bolster the construction industry over the near two years, advancing an average of 14.1 per cent per year. In addition, government investment spending will improve. All told, construction will expand by 11.5 per cent in 2015 and a further 10.4 per cent in 2016.

Manufacturing will make substantial advances over the next two years. The stronger growth in the U.S. and the weaker Canadian dollar will help make Nova Scotia-produced goods more price competitive internationally. There will be a slew of contracts to keep Nova Scotia manufacturers busy: work on the Royal Canadian Navy ships is slated to commence in September. The budget for the Arctic Offshore Patrol Ships (AOPS) is expected to total $3.5 billion. The AOPS are the first of the navy's ships to be delivered under the National Shipbuilding Procurement Strategy (NSPS) and are projected to be completed around 2018. Other proposed navy ships, such as a fleet of surface combatants and supply vessels to be built under NSPS, are still years away from construction. Currently, five AOPS are planned with a potential for a sixth ship if Irving Shipbuilding meets certain incentives. To help facilitate work on the ships, Nova Scotia and British Columbia have signed an agreement to make it easier for workers to move between shipbuilding projects in the two provinces, as the Irving Shipyard in Halifax and the Seaspan shipyard in Vancouver are both slated to begin work on these new naval ships.

Other segments of the manufacturing industry are also expected to perform well. Michelin is expanding heavy-duty-tire production at its Waterville plant in the Annapolis Valley. The expansion will enable Michelin to increase output of bus, truck, and off-road tires by 2016, which will help offset the lower production levels of car tires at Michelin's plant in Granton. In addition, investment in the aerospace and biochemical industries will support manufacturing growth. Pratt & Whitney Canada is undertaking expansions at its plant near the Halifax airport to build components of its new PurePower® PW800 engines. BioVectra, a contract manufacturing organization that produces ingredients for the global pharmaceutical industry, is investing in its newly acquired Windsor facility. Overall, the manufacturing industry will gain 3.7 per cent in 2015 and 8.2 per cent in 2016.

DOMESTIC DEMAND

Nova Scotia experienced a severe winter that affected the provincial services economy. Employment fell in the first six months of the year and, although job prospects are forecast to improve over the rest of the year, it will not be enough to offset the losses in the first half of 2015. Total employment levels will fall 0.1 per cent in 2015. Strong growth in the goods-producing sector will bring a recovery in employment next year with growth of 1 per cent. Retail trade will follow a similar trajectory—after falling in the first quarter of the year, the sector will recover and enjoy healthy gains next year, helping to lift the overall domestic economy.

Forecast Risks

Short term

- If more "fly-in, fly-out" workers residing in Nova Scotia are laid off in Alberta's energy sector, provincial employment and labour income would fall.

Medium term

- If the proposed liquefied natural gas export terminals go ahead, the province will see long-term benefits across several industries.

Source: The Conference Board of Canada.

Key Economic Indicators: Nova Scotia

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	40,255	40,103	41,190	40,547	40,758	41,549	42,092	42,770	43,063	43,467	43,911	44,102	40,524	41,792	43,636
	3.0	*-0.4*	*2.7*	*-1.6*	*0.5*	*1.9*	*1.3*	*1.6*	*0.7*	*0.9*	*1.0*	*0.4*	*3.5*	*3.1*	*4.4*
GDP at market prices (2007 $ millions)	36,441	36,431	36,698	36,871	36,708	36,948	37,117	37,514	37,728	37,900	38,137	38,169	36,610	37,072	37,984
	3.8	*0.0*	*0.7*	*0.5*	*-0.4*	*0.7*	*0.5*	*1.1*	*0.6*	*0.5*	*0.6*	*0.1*	*1.6*	*1.3*	*2.5*
GDP at basic prices (2007 $ millions)	33,325	33,317	33,561	33,719	33,569	33,789	33,944	34,307	34,502	34,660	34,877	34,906	33,480	33,902	34,736
	3.8	*0.0*	*0.7*	*0.5*	*-0.4*	*0.7*	*0.5*	*1.1*	*0.6*	*0.5*	*0.6*	*0.1*	*1.6*	*1.3*	*2.5*
Consumer price index (2002 = 1.0)	1.282	1.293	1.291	1.285	1.282	1.294	1.302	1.307	1.314	1.323	1.330	1.334	1.288	1.296	1.325
	1.2	*0.8*	*-0.1*	*-0.5*	*-0.2*	*0.9*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.7*	*0.6*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.105	1.101	1.122	1.100	1.110	1.125	1.134	1.140	1.141	1.147	1.151	1.155	1.107	1.127	1.149
	-0.7	*-0.4*	*2.0*	*-2.0*	*1.0*	*1.3*	*0.8*	*0.5*	*0.1*	*0.5*	*0.4*	*0.4*	*1.9*	*1.8*	*1.9*
Wages and salary per employee ($ 000s)	40.571	40.923	40.701	40.409	41.221	41.283	41.370	41.519	41.755	42.006	42.224	42.454	40.651	41.348	42.109
	1.5	*0.9*	*-0.5*	*-0.7*	*2.0*	*0.2*	*0.2*	*0.4*	*0.6*	*0.6*	*0.5*	*0.5*	*3.4*	*1.7*	*1.8*
Primary household income ($ millions)	29,189	29,174	29,122	29,262	29,821	29,706	29,930	30,134	30,410	30,655	30,881	31,109	29,187	29,898	30,764
	1.9	*-0.1*	*-0.2*	*0.5*	*1.9*	*-0.4*	*0.8*	*0.7*	*0.9*	*0.8*	*0.7*	*0.7*	*2.6*	*2.4*	*2.9*
Household disposable income ($ millions)	26,725	26,623	26,576	26,653	27,160	27,022	27,376	27,402	27,585	27,805	28,015	28,226	26,644	27,240	27,908
	1.7	*-0.4*	*-0.2*	*0.3*	*1.9*	*-0.5*	*1.3*	*0.1*	*0.7*	*0.8*	*0.8*	*0.8*	*2.4*	*2.2*	*2.5*
Household net savings rate (per cent)	-4.2	-5.8	-6.7	-6.2	-1.9	-4.3	-4.2	-4.9	-5.1	-5.1	-5.1	-5.0	-5.7	-3.8	-5.1
Population (000s)	943	942	943	944	944	943	943	944	945	945	946	947	943	943	946
	0.0	*-0.1*	*0.1*	*0.1*	*0.0*	*-0.1*	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	*0.2*
Employment (000s)	447	446	447	451	448	445	447	449	450	451	453	454	448	447	452
	-0.2	*-0.3*	*0.2*	*1.0*	*-0.7*	*-0.5*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.2*	*-1.1*	*-0.1*	*1.0*
Labour force (000s)	491	490	490	494	492	488	490	491	492	493	495	496	491	490	494
	-0.3	*-0.2*	*0.0*	*0.7*	*-0.4*	*-0.8*	*0.5*	*0.3*	*0.2*	*0.2*	*0.3*	*0.2*	*-1.3*	*-0.2*	*0.8*
Labour force participation rate (per cent)	62.8	62.6	62.6	63.0	62.7	62.1	62.5	62.6	62.7	62.7	62.8	62.9	62.7	62.5	62.8
Unemployment rate (per cent)	8.9	9.0	8.9	8.6	8.9	8.6	8.7	8.7	8.6	8.5	8.5	8.4	8.9	8.7	8.5
Retail sales ($ millions)	13,719	13,920	14,182	13,837	13,222	13,709	13,872	13,992	14,106	14,213	14,311	14,394	13,915	13,699	14,256
	0.6	*1.5*	*1.9*	*-2.4*	*-4.4*	*3.7*	*1.2*	*0.9*	*0.8*	*0.8*	*0.7*	*0.6*	*2.3*	*-1.6*	*4.1*
Housing starts (units, 000s)	1,972	2,577	4,546	3,128	2,183	6,011	3,069	3,070	3,177	3,170	3,167	3,219	3,056	3,583	3,183
	-44.1	*30.7*	*76.4*	*-31.2*	*-30.2*	*175.4*	*-48.9*	*0.0*	*3.5*	*-0.2*	*-0.1*	*1.6*	*-22.0*	*17.3*	*-11.2*
Net interprovincial migration (000s)	-4.0	0.3	-0.5	-1.3	-2.2	0.6	1.0	1.3	1.3	1.5	1.6	1.6	-1.4	0.2	1.5
Net international migration (000s)	2.3	2.3	4.6	0.2	1.5	1.9	2.0	2.0	2.0	2.0	1.9	1.9	2.4	1.9	1.9

Shaded 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: Nova Scotia cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	44,559	44,935	45,309	45,625	46,105	46,517	46,904	47,165	47,650	48,072	48,432	48,649	45,107	46,673	48,201
	1.0	*0.8*	*0.8*	*0.7*	*1.1*	*0.9*	*0.8*	*0.6*	*1.0*	*0.9*	*0.7*	*0.4*	*3.4*	*3.5*	*3.3*
GDP at market prices (2007 $ millions)	38,351	38,442	38,590	38,745	38,900	39,008	39,121	39,267	39,411	39,520	39,619	39,676	38,532	39,074	39,556
	0.5	*0.2*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.2*	*0.1*	*1.4*	*1.4*	*1.2*
GDP at basic prices (2007 $ millions)	35,072	35,156	35,291	35,432	35,574	35,672	35,775	35,909	36,041	36,141	36,231	36,284	35,238	35,733	36,174
	0.5	*0.2*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.2*	*0.1*	*1.4*	*1.4*	*1.2*
Consumer price index (2002 = 1.0)	1.342	1.351	1.358	1.362	1.370	1.379	1.387	1.390	1.398	1.408	1.415	1.419	1.353	1.382	1.410
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.162	1.169	1.174	1.178	1.185	1.193	1.199	1.201	1.209	1.216	1.222	1.226	1.171	1.194	1.219
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.2*	*0.7*	*0.6*	*0.5*	*0.3*	*1.9*	*2.0*	*2.0*
Wages and salary per employee ($ 000s)	42.656	42.855	43.086	43.310	43.535	43.799	44.051	44.280	44.547	44.805	45.037	45.261	42.977	43.916	44.913
	0.5	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*2.1*	*2.2*	*2.3*
Primary household income ($ millions)	31,255	31,460	31,678	31,886	32,124	32,336	32,546	32,729	32,974	33,172	33,365	33,558	31,569	32,434	33,267
	0.5	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.8*	*0.6*	*0.6*	*0.6*	*2.6*	*2.7*	*2.6*
Household disposable income ($ millions)	28,430	28,615	28,811	28,998	29,180	29,384	29,578	29,746	29,952	30,144	30,321	30,491	28,714	29,472	30,227
	0.7	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*0.7*	*0.6*	*0.7*	*0.6*	*0.6*	*0.6*	*2.9*	*2.6*	*2.6*
Household net savings rate (per cent)	–4.8	–4.8	–4.8	–4.8	–4.8	–4.8	–4.7	–4.8	–4.7	–4.6	–4.6	–4.5	–4.8	–4.8	–4.6
Population (000s)	948	948	949	950	951	952	952	953	953	954	955	955	949	952	954
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.3*	*0.3*	*0.2*
Employment (000s)	454	455	455	456	456	456	456	456	456	457	457	458	455	456	457
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.0*	*0.1*	*0.0*	*0.1*	*0.1*	*0.6*	*0.3*	*0.2*
Labour force (000s)	496	496	496	496	496	496	496	496	496	496	496	496	496	496	496
	0.1	*0.0*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.4*	*0.0*	*0.0*
Labour force participation rate (per cent)	62.8	62.8	62.7	62.7	62.6	62.6	62.5	62.4	62.4	62.4	62.3	62.3	62.8	62.6	62.4
Unemployment rate (per cent)	8.4	8.3	8.2	8.2	8.2	8.1	8.0	8.0	8.0	7.9	7.9	7.8	8.3	8.1	7.9
Retail sales ($ millions)	14,439	14,497	14,569	14,648	14,728	14,808	14,880	14,941	15,022	15,086	15,148	15,200	14,538	14,839	15,114
	0.3	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*0.5*	*0.4*	*0.4*	*0.3*	*2.0*	*2.1*	*1.9*
Housing starts (units, 000s)	3,256	3,223	3,177	3,144	3,097	3,064	3,018	2,985	2,940	2,906	2,860	2,827	3,200	3,041	2,883
	1.1	*–1.0*	*–1.4*	*–1.0*	*–1.5*	*–1.1*	*–1.5*	*–1.1*	*–1.5*	*–1.1*	*–1.6*	*–1.2*	*0.5*	*–5.0*	*–5.2*
Net interprovincial migration (000s)	1.6	1.6	1.6	1.5	1.2	1.1	1.0	1.0	0.9	0.9	0.8	0.8	1.6	1.1	0.9
Net international migration (000s)	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.9	1.8	1.7

Shaded 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.

Natalia Ward

New Brunswick's Economic Outlook Improves

Highlights

- Metal mining will benefit from the reopening of Trevali's previously closed Caribou mine.
- Investments in the forestry sector will boost domestic demand.
- Employment will see another disappointing year with another reduction in the number of people employed.

Economic Indicators

(percentage change)

	2014	2015f	2016f
Real GDP	0.0	1.4	2.0
Consumer Price Index	1.5	0.9	2.3
Household disposable income	0.6	1.5	2.8
Employment	−0.2	−0.1	1.1
Unemployment rate (level)	9.9	10.0	9.5
Retail sales	3.8	1.1	4.3
Wages and salaries per employee	1.3	1.7	2.2
Population	−0.2	−0.1	0.1

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

Government and Background Information

Premier	Brian Gallant
Next election	2019
Population (2015Q2)	753,319
Government balance (2015–16)	−$476.8 million

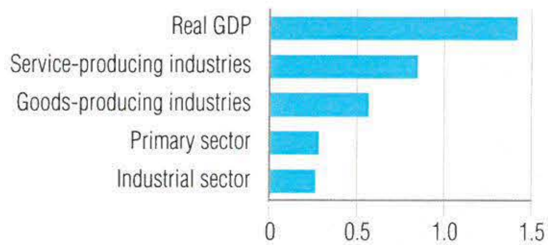
Source: The Conference Board of Canada; New Brunswick budget documents.

A rebound in the goods-producing industries and better growth in the services sector will generate an improved economic outlook for New Brunswick in the next two years. Real GDP is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Decent gains in mining, manufacturing, agriculture, and forestry will help lift growth in the goods-producing industries. Potash mining will continue to ramp up at the Picadilly mine, while metal mining will benefit from the reopening of Trevali's Caribou mine (the company expects to more than double its zinc production). Manufacturing will also post solid gains over the next two years. Stronger economic growth in the U.S. will help drive demand for New Brunswick–produced goods, while a weaker Canadian dollar will make them more price competitive. The forestry industry will benefit from an increase in the allowable softwood cut on Crown land and stronger growth in new housing demand in the U.S. In addition, the industry will benefit from the $450-million investment by J.D. Irving in the province's lumber mill upgrades. Construction, on the other hand, will weigh down overall growth. Private investment in residential and non-residential structures is forecast to decline this year as a number of non-residential projects are completed and housing starts fall off.

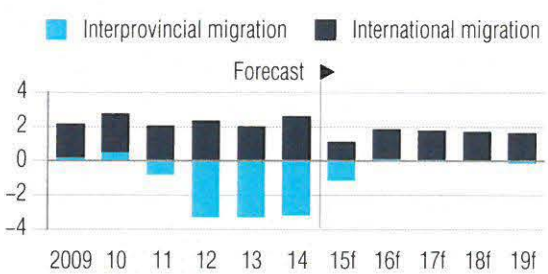
The short-term outlook for services-producing industries is somewhat weaker. Although some commercial services are experiencing solid growth, the

Contributions to New Brunswick Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



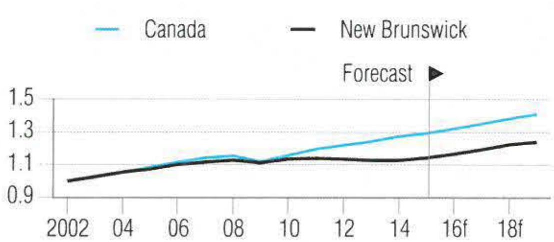
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

retail industry suffered a difficult start to the year as unseasonably cold weather kept many residents at home. Employment growth is projected to decline slightly this year, mainly due to the contraction in the construction sector.

MINING REBOUNDS

Although global metal and mineral prices have not picked up, mining in New Brunswick will perform quite well over the next two years. Metal mining will benefit from the reopening of Trevali's previously closed Caribou mine that began production this year and that will continue to ramp up production throughout the summer months. Trevali intends to increase total production more than twofold to 5,000 metric tonnes of ore per day by 2016 and will focus not only on zinc but also on copper and lead. Coming off a very low base year in 2014, metal mining will post substantial increases in 2015 and 2016.

Non-metallic mining and quarrying will perform well over the near term. After the market turmoil two years ago due to the collapse of the Russian–Belarussian cartel and the subsequent plunge in potash prices, this year's contracts with India and China have shown some price improvements. Further, there is upside potential for potash prices as Russia is facing difficulties with its Solikamsk-2 potash mine (brine inflow problems). New Brunswick's Picadilly mine will continue to increase production over the next two years, leading to a 5.2 per cent increase in non-metallic mining and quarrying in 2015 and by a 19.6 per cent gain in 2016. All told, mining will rise by 12.9 per cent in 2015 and increase a further 19.8 per cent in 2016.

FISHING, AGRICULTURE, AND FORESTRY WILL SEE DECENT GROWTH

The outlook for "other primary" industries—which include agriculture, fishing, hunting, trapping, and forestry—is also looking positive. The agriculture industry is forecast to rebound and post healthy gains this year and next. Fishing and trapping saw a 10.3 per cent increase last year and is expecting another strong year with growth of 5.8 per cent in 2015. The province and the federal government are investing in seven projects in the oyster industry—a total of $1.2 million that will support operational expansions, increased efficiencies, increased sales opportunities, and productivity improvements. On the downside, growth in the fishing industry will be limited by the recently imposed moratorium on Atlantic salmon fishing. Salmon fishing in New Brunswick (and Nova Scotia) will be limited to catch-and-release.

Output in the forestry sector will continue to enjoy strong gains over the near term. Demand for forestry products is increasing and will be supported by a robust expansion in housing starts in the U.S. This will help drive up prices for lumber and other wood products and allow some currently idle mills to restart operations. In addition, the provincial government announced a 20 per cent increase in allowable timber cuts. In response, J.D. Irving will invest about $450 million to upgrade its mills over the next two years. According to the New Brunswick's forestry association (Forest NB), almost $1 billion is expected to be spent on mills across the province to increase capacity over the medium term. The mill upgrades will be the first major new business investment in the province since 2008 and should help the forestry industry grow and generate spillover effects for the rest of the economy. All told, the forestry industry is forecast to expand by 4.9 per cent in 2015 and 3.1 per cent in 2016.

MANUFACTURING ALSO REBOUNDING

Manufacturing is expected to recover this year, supported by increasing demand for building materials south of the border. Refined crude oil product volumes are forecast to rally as the Irving refinery is once again in full operation after an unplanned shutdown last year. Food manufacturing will benefit from expanded capacity in berry processing by Oxford Frozen Foods. Finally, a weaker Canadian dollar will also help make New Brunswick–manufactured goods more price competitive on the export market and will support international demand for provincial goods. All told, manufacturing will grow by 3 per cent in 2015 and 2.7 per cent in 2016.

CONSTRUCTION FALTERS

Construction is forecast to decline this year. Cold weather and snow put the freeze on new home construction in the province. In the first six months of the year, new housing starts fell by 690 units. Although the number of starts is expected to recover toward the end of the year, overall annual residential investment spending will fall in 2015 before recovering in 2016. Non-residential business investment will also decline in 2015 as several projects are coming to an end, including the Oxford Frozen Foods berry processing facility and Phase 1 of the J.D. Irving investment in the forestry sector. Investment in machinery and equipment and government investment spending, on the other hand, will see healthy gains in 2015–16.

DOMESTIC DEMAND OUTLOOK

The services sector will benefit from healthy advances in transportation and warehousing, finance and insurance, real estate, and leasing. On the downside, provincial retailers were hard hit by a cold and snowy winter and will not be able to recoup losses of the first six months of this year; therefore, there will be only a modest gain in retail trade in 2015. Employment will see another disappointing year with a further reduction in the number of people employed (down 0.1 per cent) but job prospects will improve next year (up 1.1 per cent).

Forecast Risks

Short term

- If more "fly-in, fly-out" workers—those who are involved in the Alberta energy sector and reside in New Brunswick—are out of work for an extended period, employment and labour income could be further reduced.

Medium term

- The reconfiguration of the Canaport liquid natural gas (LNG) import terminal into an export terminal could bring huge benefits to the province.

Source: The Conference Board of Canada.

Key Economic Indicators: New Brunswick

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	31,634	31,882	32,792	32,969	32,824	33,217	33,666	34,025	34,193	34,548	34,928	35,215	32,319	33,433	34,721
	–1.8	*0.8*	*2.9*	*0.5*	*–0.4*	*1.2*	*1.4*	*1.1*	*0.5*	*1.0*	*1.1*	*0.8*	*1.3*	*3.4*	*3.9*
GDP at market prices (2007 $ millions)	27,779	27,939	28,652	28,675	28,567	28,545	28,692	28,849	28,970	29,138	29,351	29,496	28,261	28,663	29,239
	–3.1	*0.6*	*2.6*	*0.1*	*–0.4*	*–0.1*	*0.5*	*0.5*	*0.4*	*0.6*	*0.7*	*0.5*	*0.0*	*1.4*	*2.0*
GDP at basic prices (2007 $ millions)	25,618	25,766	26,423	26,444	26,345	26,325	26,460	26,605	26,716	26,871	27,067	27,201	26,063	26,434	26,964
	–3.1	*0.6*	*2.6*	*0.1*	*–0.4*	*–0.1*	*0.5*	*0.5*	*0.4*	*0.6*	*0.7*	*0.5*	*0.0*	*1.4*	*2.0*
Consumer price index (2002 = 1.0)	1.243	1.251	1.250	1.248	1.243	1.257	1.265	1.270	1.277	1.286	1.292	1.296	1.248	1.259	1.288
	0.6	*0.6*	*–0.1*	*–0.1*	*–0.5*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.5*	*0.9*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.139	1.141	1.145	1.150	1.149	1.164	1.173	1.179	1.180	1.186	1.190	1.194	1.144	1.166	1.187
	1.3	*0.2*	*0.3*	*0.5*	*–0.1*	*1.3*	*0.8*	*0.5*	*0.1*	*0.5*	*0.4*	*0.3*	*1.3*	*2.0*	*1.8*
Wages and salary per employee ($ 000s)	39.739	40.341	40.709	40.680	40.915	40.976	41.063	41.264	41.463	41.830	42.104	42.358	40.367	41.054	41.939
	0.2	*1.5*	*0.9*	*–0.1*	*0.6*	*0.2*	*0.2*	*0.5*	*0.5*	*0.9*	*0.7*	*0.6*	*1.3*	*1.7*	*2.2*
Primary household income ($ millions)	21,953	21,951	22,097	22,086	22,461	22,337	22,523	22,731	22,906	23,168	23,371	23,570	22,022	22,513	23,254
	1.0	*0.0*	*0.7*	*0.0*	*1.7*	*–0.5*	*0.8*	*0.9*	*0.8*	*1.1*	*0.9*	*0.9*	*1.4*	*2.2*	*3.3*
Household disposable income ($ millions)	20,817	20,790	20,910	20,886	21,104	20,937	21,271	21,318	21,438	21,677	21,853	22,029	20,851	21,158	21,749
	0.4	*–0.1*	*0.6*	*–0.1*	*1.0*	*–0.8*	*1.6*	*0.2*	*0.6*	*1.1*	*0.8*	*0.8*	*0.6*	*1.5*	*2.8*
Household net savings rate (per cent)	–0.5	–2.1	–2.9	–2.5	–0.8	–2.8	–2.6	–3.3	–3.5	–3.5	–3.5	–3.4	–2.0	–2.4	–3.5
Population (000s)	755	754	754	755	754	753	753	754	754	754	755	755	754	754	754
	0.0	*–0.1*	*0.0*	*0.1*	*–0.1*	*–0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*–0.2*	*–0.1*	*0.1*
Employment (000s)	357	353	353	352	354	351	353	355	355	357	358	359	354	353	357
	0.3	*–1.1*	*–0.1*	*–0.3*	*0.7*	*–0.7*	*0.5*	*0.4*	*0.2*	*0.4*	*0.3*	*0.3*	*–0.2*	*–0.1*	*1.1*
Labour force (000s)	396	393	391	390	394	391	392	393	394	395	395	396	392	393	395
	0.3	*–0.8*	*–0.5*	*–0.1*	*0.9*	*–0.7*	*0.3*	*0.2*	*0.1*	*0.3*	*0.1*	*0.1*	*–0.6*	*0.0*	*0.6*
Labour force participation rate (per cent)	63.6	63.2	62.9	62.8	63.3	62.9	63.1	63.2	63.3	63.5	63.5	63.5	63.1	63.1	63.4
Unemployment rate (per cent)	9.8	10.1	9.8	10.0	10.2	10.1	9.9	9.8	9.7	9.6	9.4	9.2	9.9	10.0	9.5
Retail sales ($ millions)	11,320	11,477	11,745	11,571	11,343	11,595	11,770	11,891	11,976	12,120	12,218	12,304	11,528	11,650	12,155
	1.3	*1.4*	*2.3*	*–1.5*	*–2.0*	*2.2*	*1.5*	*1.0*	*0.7*	*1.2*	*0.8*	*0.7*	*3.8*	*1.1*	*4.3*
Housing starts (units, 000s)	2,218	1,811	2,769	2,306	1,926	1,615	1,470	1,641	1,633	1,816	1,791	1,775	2,276	1,663	1,753
	–24.2	*–18.3*	*52.9*	*–16.7*	*–16.5*	*–16.1*	*–8.9*	*11.6*	*–0.5*	*11.2*	*–1.4*	*–0.9*	*–19.9*	*–26.9*	*5.4*
Net interprovincial migration (000s)	–3.1	–4.7	–3.3	–1.7	–2.5	–1.0	–0.7	–0.4	–0.1	0.1	0.2	0.3	–3.2	–1.1	0.1
Net international migration (000s)	0.9	4.2	5.2	0.2	0.1	1.0	1.7	1.7	1.7	1.7	1.7	1.7	2.6	1.1	1.7

Shaded 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: New Brunswick cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	35,671	36,058	36,443	36,779	37,331	37,735	38,078	38,265	38,590	38,887	39,110	39,225	36,238	37,852	38,953
	1.3	*1.1*	*1.1*	*0.9*	*1.5*	*1.1*	*0.9*	*0.5*	*0.8*	*0.8*	*0.6*	*0.3*	*4.4*	*4.5*	*2.9*
GDP at market prices (2007 $ millions)	29,714	29,865	30,061	30,263	30,539	30,695	30,823	30,933	31,006	31,071	31,110	31,122	29,976	30,747	31,077
	0.7	*0.5*	*0.7*	*0.7*	*0.9*	*0.5*	*0.4*	*0.4*	*0.2*	*0.2*	*0.1*	*0.0*	*2.5*	*2.6*	*1.1*
GDP at basic prices (2007 $ millions)	27,402	27,541	27,722	27,908	28,162	28,306	28,424	28,525	28,592	28,653	28,689	28,700	27,643	28,354	28,659
	0.7	*0.5*	*0.7*	*0.7*	*0.9*	*0.5*	*0.4*	*0.4*	*0.2*	*0.2*	*0.1*	*0.0*	*2.5*	*2.6*	*1.1*
Consumer price index (2002 = 1.0)	1.304	1.313	1.319	1.323	1.331	1.340	1.347	1.351	1.359	1.368	1.375	1.379	1.315	1.342	1.370
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.200	1.207	1.212	1.215	1.222	1.229	1.235	1.237	1.245	1.252	1.257	1.260	1.209	1.231	1.253
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.6*	*0.4*	*0.3*	*1.8*	*1.8*	*1.8*
Wages and salary per employee ($ 000s)	42.616	42.855	43.121	43.399	43.678	43.938	44.198	44.455	44.717	44.951	45.207	45.418	42.998	44.068	45.073
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.5*	*2.5*	*2.5*	*2.3*
Primary household income ($ millions)	23,762	23,989	24,230	24,474	24,745	24,987	25,200	25,357	25,535	25,670	25,828	25,968	24,114	25,072	25,750
	0.8	*1.0*	*1.0*	*1.0*	*1.1*	*1.0*	*0.9*	*0.6*	*0.7*	*0.5*	*0.6*	*0.5*	*3.7*	*4.0*	*2.7*
Household disposable income ($ millions)	22,245	22,445	22,657	22,869	23,083	23,302	23,493	23,639	23,783	23,924	24,071	24,211	22,554	23,379	23,997
	1.0	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*0.8*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*3.7*	*3.7*	*2.6*
Household net savings rate (per cent)	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.1	-3.2	-3.1	-3.0	-3.0	-2.8	-3.2	-3.2	-3.0
Population (000s)	756	756	757	757	757	758	758	759	759	759	760	760	756	758	759
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.2*	*0.2*	*0.2*
Employment (000s)	360	362	363	365	366	368	369	369	369	369	369	369	363	368	369
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*1.5*	*1.5*	*0.3*
Labour force (000s)	396	396	398	399	400	401	401	401	400	400	400	400	397	401	400
	0.0	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*0.1*	*0.0*	*–0.2*	*0.0*	*–0.1*	*0.1*	*0.6*	*0.9*	*–0.2*
Labour force participation rate (per cent)	63.4	63.5	63.7	63.8	63.9	64.0	64.1	64.0	63.8	63.8	63.7	63.7	63.6	64.0	63.8
Unemployment rate (per cent)	8.9	8.7	8.6	8.5	8.4	8.2	8.0	8.0	7.8	7.8	7.7	7.7	8.7	8.2	7.8
Retail sales ($ millions)	12,389	12,483	12,592	12,711	12,835	12,949	13,043	13,111	13,172	13,225	13,287	13,339	12,544	12,984	13,256
	0.7	*0.8*	*0.9*	*0.9*	*1.0*	*0.9*	*0.7*	*0.5*	*0.5*	*0.4*	*0.5*	*0.4*	*3.2*	*3.5*	*2.1*
Housing starts (units, 000s)	1,903	1,888	1,863	1,848	2,023	2,008	1,984	1,969	2,145	2,130	2,105	2,089	1,875	1,996	2,117
	7.2	*–0.8*	*–1.3*	*–0.8*	*9.5*	*–0.8*	*–1.2*	*–0.8*	*9.0*	*–0.7*	*–1.1*	*–0.8*	*7.0*	*6.4*	*6.1*
Net interprovincial migration (000s)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	–0.1	–0.1	–0.2	–0.2	0.1	0.1	–0.1
Net international migration (000s)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.7	1.7	1.6

Shaded 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.

Elise Martin

Quebec's Export Recovery Stalls Amidst U.S. Winter Doldrums

Highlights

- Housing starts are expected to plunge by 6,400 units this year.
- A bad first quarter will slow growth in exports of goods and services to just 1.1 per cent this year.
- Real business investment is stuck in a slump and will contract by an additional 2.9 per cent this year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.4	1.9	2.0
Consumer Price Index	1.4	1.3	2.2
Household disposable income	2.3	3.1	2.9
Employment	–0.1	1.1	1.0
Unemployment rate (level)	7.8	7.8	8.0
Retail sales	1.7	1.7	3.7
Wages and salaries per employee	2.0	1.3	2.0
Population	0.8	0.6	0.9

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

Government and Background Information

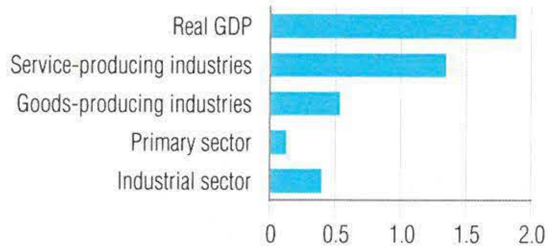
Premier	Philippe Couillard
Next election	2018
Population (2015Q2)	8,245,470
Government balance (2015–16)	0 (balanced)

Sources: Statistics Canada; Provincial budget documents.

Despite the weaker-than-expected performance of its trade sector, Quebec's economy will strengthen this year, advancing by 1.9 per cent, compared with 1.4 per cent last year. Next year, Quebec's GDP is forecast to expand by 2 per cent. The temporary slowdown in Quebec's exports is due to the exceptionally low final demand from U.S. businesses and consumers in the first quarter of 2015. Quebec's exports of goods to other countries jumped by a solid 9.4 per cent last year but will post a meagre 0.8 per cent increase this year due to a very bad first quarter. The U.S. economy suffered a transitory setback with a port strike on the West Coast and exceptionally cold weather on the East Coast this winter. As a result, Quebec's exports of goods and services, which posted 3.9 per cent growth in 2014, will advance by 1.1 per cent this year before rising 3.4 per cent in 2016.

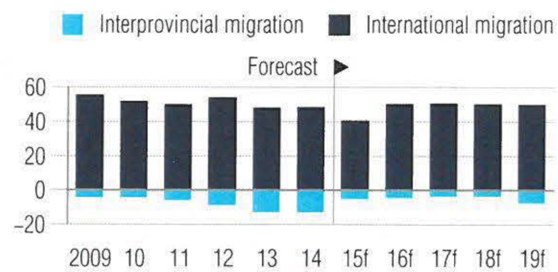
The trade slowdown this year will in turn cause Quebec's export-oriented manufacturing industry to grow by just 1.7 per cent in 2015. Weak demand south of the border will also persuade domestic businesses not to move forward with major investment projects. Non-residential construction and machinery and equipment investment will falter again this year, by 8.2 per cent and 2.1 per cent respectively, before they firm up in 2016 and post 2.4 per cent and 2.3 per cent increases, respectively.

Contributions to Quebec Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



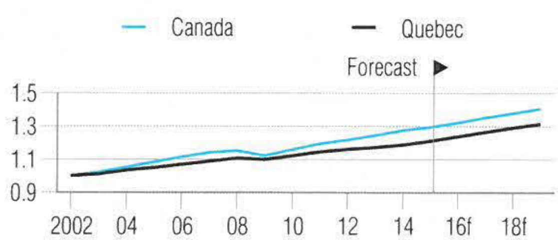
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

Thanks to a 1.1 per cent increase in employment this year, stronger growth in household disposable income will help lift wholesale and retail trade by 2.6 per cent. Once again, consumer spending will support the economic performance of the province while the government holds growth on program expenditures to just 1.2 per cent in 2015–16.

THE EXPORT RECOVERY IS STALLING TEMPORARILY

With a recovery in exports, the decline in the trade deficit was responsible for half the growth in the province's real GDP in 2014, as Quebec's exports grew by 3.9 per cent. However, the U.S. economy has been hit by a bad case of winter doldrums, severely lowering U.S. final demand in the first quarter of the year and affecting Quebec's exports of goods and services, which will increase by only 1.1 per cent this year. The slump in U.S. final demand was temporary, caused by an historic strike by port workers on the West Coast and an exceptionally cold winter. However, the strength of the greenback could impose a heavier drag than expected on U.S. economic activity, as U.S. exporters sell fewer products abroad due to their high relative price. Nevertheless, solid fundamentals are in place to support stronger economic growth south of the border and, in light of encouraging employment numbers, the U.S. economy is forecast to grow by 2.2 per cent in 2015. This, together with the Canadian dollar that remains well below parity, adds optimism to the trade sector outlook.

Primary metals, aerospace products, paper and wood products, and electronics will be fuelling growth in Quebec's exports. Despite Bombardier's setbacks in developing the C Series aircraft and its recent massive waves of layoffs, other companies are faring better. Pratt & Whitney Canada motors will propel Gulfstream's new business jets with the engines being built in Mirabel. Héroux-Devtek landed the most important landing-gear contract in its history and will equip the new Boeing 777. Part of this production will take place in Laval. Quebec exports are poised to rebound and grow 3.4 per cent in 2016 and 3.2 per cent in 2017.

BUSINESS INVESTMENT TO RETREAT AGAIN

Amid the uncertainty brought about by the collapse in crude oil prices, businesses in Canada pulled back on capital plans in the first quarter of 2015. However, the Conference Board's business confidence index shows that confidence has now rebounded. Of the firms surveyed, the numbers saying the present was a bad time to invest decreased substantially, going from 27.3 per cent this winter to 12.9 per cent in the latest survey. Meanwhile, indicators of capacity pressures are emitting mixed signals. The share of firms stating that they were operating at, close to, or above capacity firmed up to 45.1 per cent in this last survey, up from 29.5 per cent in the previous survey.

Nevertheless, this recent optimistic trend will not be enough to offset the contraction in business investment that occurred in the first half of the year. Accordingly, a 2.9 per cent decline is expected in business investment this year in the province. A turnaround is anticipated next year as both investment in machinery and equipment and in non-residential construction will bounce back and grow by 2.3 and 2.4 per cent respectively. All in all, the Conference Board forecasts positive growth of 0.5 per cent in 2016 and 3.3 per cent in 2017 for real business investment.

CONSUMER SPENDING HOLDING FIRM

Indebted consumers, who are supporting economic growth with their spending, should be passing the baton to businesses. But firms are not playing along and are hesitating to expand capacity; therefore, consumer spending will continue to be a key contributor to the Quebec economy in 2015, accounting for close to 75 per cent of the increase in real GDP this year. In 2014, household final consumption expenditures were surprisingly resilient, growing by 2 per cent; this was despite the absence of job creation and an increase in household disposable income that was below the 10-year average. But, to maintain their spending, consumers have had to save less and rely more heavily on debt. The savings rate in the province, therefore, has fallen significantly and fell to 1.5 per cent in 2014, down from 2.7 per cent in 2013. This year, the labour market is generating more jobs. Employment is expected to be up by 1.1 per cent, providing a boost to households' real purchasing power. This, along with the lower gasoline prices, an increasing reliance on credit, and federal government transfers, will permit consumers to continue acting as the locomotive of Quebec's economy.

HAVOC IN THE CONSTRUCTION INDUSTRY

Hampered by a big retreat in multiple-unit housing starts, Quebec's construction industry will contract for the third year in a row, down by 1.3 percent. This will lead to about 9,400 construction workers losing their jobs in 2015. The adverse situation is expected to continue next year, with the employment level in the construction sector down by 12.2 per cent from its peak of 2013. Large infrastructure projects—such as the replacement of the Champlain Bridge and the reconstruction of the Turcot Interchange in Montréal—will not be enough to offset the plunge in housing starts and the lull in private non-residential projects.

Forecast Risks

Short term

- Large-scale mobilization of public sector unions could disrupt the economy this fall as negotiations for new collective agreements take place.

Medium term

- A U.S. economy, hampered by the rise of the greenback, could turn in a lower-than-expected performance, disrupting the export recovery experienced by Quebec's manufacturing industry.

Source: The Conference Board of Canada.

Key Economic Indicators: Quebec

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	368,971	373,037	377,049	378,351	377,417	382,743	387,809	391,551	393,402	397,453	401,694	404,766	374,352	384,880	399,329
	0.9	*1.1*	*1.1*	*0.3*	*-0.2*	*1.4*	*1.3*	*1.0*	*0.5*	*1.0*	*1.1*	*0.8*	*3.2*	*2.8*	*3.8*
GDP at market prices (2007 $ millions)	334,039	335,312	337,167	337,550	338,909	341,423	343,532	345,281	346,161	348,112	350,496	351,970	336,017	342,286	349,185
	0.2	*0.4*	*0.6*	*0.1*	*0.4*	*0.7*	*0.6*	*0.5*	*0.3*	*0.6*	*0.7*	*0.4*	*1.4*	*1.9*	*2.0*
GDP at basic prices (2007 $ millions)	309,964	311,175	312,900	313,260	314,853	316,869	318,699	320,324	321,161	322,974	325,315	326,811	311,825	317,686	324,065
	0.2	*0.4*	*0.6*	*0.1*	*0.5*	*0.6*	*0.6*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*1.4*	*1.9*	*2.0*
Consumer price index (2002 = 1.0)	1.224	1.237	1.238	1.236	1.237	1.248	1.255	1.260	1.267	1.276	1.283	1.287	1.234	1.250	1.278
	0.6	*1.1*	*0.1*	*-0.1*	*0.1*	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.4*	*1.3*	*2.2*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.105	1.113	1.118	1.121	1.114	1.121	1.129	1.134	1.136	1.142	1.146	1.150	1.114	1.124	1.144
	0.7	*0.7*	*0.5*	*0.2*	*-0.6*	*0.7*	*0.7*	*0.5*	*0.2*	*0.5*	*0.4*	*0.3*	*1.7*	*0.9*	*1.7*
Wages and salary per employee ($ 000s)	40.344	40.850	41.096	41.037	40.881	41.351	41.501	41.684	41.892	42.066	42.300	42.522	40.832	41.354	42.195
	0.7	*1.3*	*0.6*	*-0.1*	*-0.4*	*1.2*	*0.4*	*0.4*	*0.5*	*0.4*	*0.6*	*0.5*	*2.0*	*1.3*	*2.0*
Primary household income ($ millions)	251,584	253,349	255,089	255,714	257,896	260,111	262,187	264,088	266,541	268,629	270,987	273,286	253,934	261,070	269,861
	0.8	*0.7*	*0.7*	*0.2*	*0.9*	*0.9*	*0.8*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*2.4*	*2.8*	*3.4*
Household disposable income ($ millions)	220,872	222,738	224,591	225,516	227,277	228,921	232,402	232,571	233,959	235,821	237,893	240,062	223,429	230,293	236,934
	1.0	*0.8*	*0.8*	*0.4*	*0.8*	*0.7*	*1.5*	*0.1*	*0.6*	*0.8*	*0.9*	*0.9*	*2.3*	*3.1*	*2.9*
Household net savings rate (per cent)	1.8	1.3	1.6	1.3	1.9	1.3	1.4	0.8	0.6	0.6	0.6	0.7	1.5	1.4	0.6
Population (000s)	8179	8191	8215	8236	8240	8245	8264	8283	8302	8320	8339	8357	8205	8258	8329
	0.1	*0.1*	*0.3*	*0.3*	*0.0*	*0.1*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.8*	*0.6*	*0.9*
Employment (000s)	4066	4043	4056	4060	4090	4098	4108	4112	4124	4137	4149	4161	4056	4102	4143
	-0.2	*-0.5*	*0.3*	*0.1*	*0.7*	*0.2*	*0.2*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*-0.1*	*1.1*	*1.0*
Labour force (000s)	4406	4390	4403	4394	4417	4440	4462	4475	4489	4499	4510	4520	4398	4449	4504
	-0.1	*-0.4*	*0.3*	*-0.2*	*0.5*	*0.5*	*0.5*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.1*	*1.1*	*1.3*
Labour force participation rate (per cent)	65.0	64.6	64.6	64.4	64.7	64.9	65.2	65.3	65.4	65.4	65.4	65.5	64.7	65.0	65.4
Unemployment rate (per cent)	7.7	7.9	7.9	7.6	7.4	7.7	7.9	8.1	8.1	8.1	8.0	8.0	7.8	7.8	8.0
Retail sales ($ millions)	106,314	108,968	109,062	108,205	107,520	109,553	111,054	111,961	112,772	113,638	114,603	115,512	108,137	110,022	114,131
	-1.1	*2.5*	*0.1*	*-0.8*	*-0.6*	*1.9*	*1.4*	*0.8*	*0.7*	*0.8*	*0.8*	*0.8*	*1.7*	*1.7*	*3.7*
Housing starts (units, 000s)	38,874	39,173	37,181	40,012	28,222	35,801	32,893	32,683	31,880	31,635	31,429	31,364	38,810	32,400	31,577
	-1.1	*0.8*	*-5.1*	*7.6*	*-29.5*	*26.9*	*-8.1*	*-0.6*	*-2.5*	*-0.8*	*-0.7*	*-0.2*	*2.8*	*-16.5*	*-2.5*
Net interprovincial migration (000s)	-10.2	-15.4	-20.1	-6.6	-10.4	-5.2	-3.0	-2.3	-3.6	-4.3	-4.5	-4.5	-13.1	-5.2	-4.2
Net international migration (000s)	40.4	83.1	69.0	2.4	25.3	37.4	50.3	50.5	50.3	50.4	50.5	50.6	48.7	40.9	50.5

Shaded area represents forecast data.

All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.

Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Quebec cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	409,967	414,080	418,090	421,494	426,381	430,526	434,478	437,007	441,188	445,128	448,529	450,927	415,908	432,098	446,443
	1.3	*1.0*	*1.0*	*0.8*	*1.2*	*1.0*	*0.9*	*0.6*	*1.0*	*0.9*	*0.8*	*0.5*	*4.2*	*3.9*	*3.3*
GDP at market prices (2007 $ millions)	354,409	355,849	357,748	359,678	361,596	362,991	364,493	366,113	367,378	368,635	369,843	370,954	356,921	363,798	369,202
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.2*	*1.9*	*1.5*
GDP at basic prices (2007 $ millions)	329,194	330,658	332,549	334,470	336,378	337,806	339,337	340,980	342,295	343,605	344,872	346,051	331,718	338,625	344,206
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.4*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*2.4*	*2.1*	*1.6*
Consumer price index (2002 = 1.0)	1.294	1.304	1.310	1.314	1.321	1.331	1.337	1.341	1.349	1.358	1.365	1.369	1.305	1.333	1.360
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.157	1.164	1.169	1.172	1.179	1.186	1.192	1.194	1.201	1.208	1.213	1.216	1.165	1.188	1.209
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.8*
Wages and salary per employee ($ 000s)	42.762	43.017	43.273	43.523	43.769	44.091	44.345	44.636	44.926	45.210	45.502	45.799	43.144	44.210	45.359
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*2.2*	*2.5*	*2.6*
Primary household income ($ millions)	275,636	278,287	280,963	283,614	286,073	288,787	291,002	293,517	296,131	298,527	300,844	303,179	279,625	289,845	299,670
	0.9	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*3.6*	*3.7*	*3.4*
Household disposable income ($ millions)	243,203	245,460	247,713	249,948	251,890	254,278	256,267	258,447	260,470	262,665	264,721	266,730	246,581	255,220	263,647
	1.3	*0.9*	*0.9*	*0.9*	*0.8*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*4.1*	*3.5*	*3.3*
Household net savings rate (per cent)	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.1	1.1	1.2	0.9	0.9	1.1
Population (000s)	8,374	8,392	8,410	8,428	8,446	8,464	8,482	8,500	8,517	8,534	8,550	8,567	8,401	8,473	8,542
	0.2	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.9*	*0.9*	*0.8*
Employment (000s)	4,175	4,189	4,203	4,217	4,226	4,234	4,241	4,250	4,258	4,267	4,273	4,279	4,196	4,238	4,269
	0.3	*0.3*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*1.3*	*1.0*	*0.7*
Labour force (000s)	4,529	4,537	4,547	4,557	4,565	4,569	4,574	4,579	4,584	4,588	4,593	4,597	4,543	4,572	4,590
	0.2	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.8*	*0.6*	*0.4*
Labour force participation rate (per cent)	65.5	65.5	65.5	65.6	65.6	65.5	65.5	65.4	65.4	65.4	65.3	65.3	65.5	65.5	65.4
Unemployment rate (per cent)	7.8	7.7	7.6	7.4	7.4	7.3	7.3	7.2	7.1	7.0	7.0	6.9	7.6	7.3	7.0
Retail sales ($ millions)	116,719	117,602	118,557	119,607	120,512	121,561	122,367	123,324	124,147	124,999	125,834	126,580	118,121	121,941	125,390
	1.0	*0.8*	*0.8*	*0.9*	*0.8*	*0.9*	*0.7*	*0.8*	*0.7*	*0.7*	*0.7*	*0.6*	*3.5*	*3.2*	*2.8*
Housing starts (units, 000s)	33,525	33,468	33,265	33,207	33,403	33,346	33,147	33,089	33,102	33,046	32,848	32,787	33,366	33,246	32,946
	6.9	*−0.2*	*−0.6*	*−0.2*	*0.6*	*−0.2*	*−0.6*	*−0.2*	*0.0*	*−0.2*	*−0.6*	*−0.2*	*5.7*	*−0.4*	*−0.9*
Net interprovincial migration (000s)	−3.8	−3.8	−3.6	−3.5	−2.9	−3.3	−3.7	−4.5	−6.8	−7.4	−7.5	−7.7	−3.7	−3.6	−7.4
Net international migration (000s)	50.9	51.0	51.0	50.9	50.6	50.5	50.4	50.3	50.2	50.1	50.1	50.0	50.9	50.5	50.1

Shaded 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.

Elise Martin

La reprise des exportations du Québec ralentie par un hiver difficile aux États-Unis

Faits saillants

- Cette année, une baisse de 6400 unités dans les mises en chantier devrait faire perdre 9400 emplois dans l'industrie de la construction.
- Les mauvais résultats du premier trimestre limiteront à 1,1 % la hausse des exportations de biens et services.
- Les investissements réels des entreprises demeurent en déclin et diminueront cette année de 2,9 %.

Indicateurs économiques
(variation en %)

	2014	2015p	2016p
PIB réel au prix de base	1,4	1,9	2,0
IPC	1,4	1,3	2,2
Revenu disponible des ménages	2,3	3,1	2,9
Emploi	–0,1	1,1	1,0
Taux de chômage	7,8	7,8	8,0
Ventes au détail	1,7	1,7	3,7
Salaires, par employé	2,0	1,3	2,0
Population	0,8	0,6	0,9

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

Renseignements généraux et sur le gouvernement

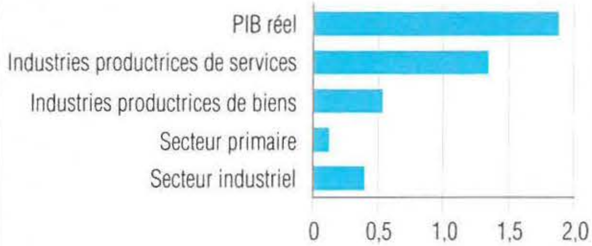
Premier ministre	Philippe Couillard
Prochaines élections	2018
Population (T2, 2015)	8 245 470
Solde budgétaire de l'État (2015–2016)	0 (équilibre)

Sources : Statistique Canada; documentation du budget provincial.

En dépit de résultats moins bons que prévu dans le commerce extérieur, l'économie du Québec se renforcera cette année, progressant de 1,9 % comparativement à 1,4 % l'an dernier. L'an prochain, le gain devrait être plus important, soit de 2 %. Le ralentissement temporaire des exportations du Québec est attribuable à la demande finale exceptionnellement faible des entreprises et des consommateurs américains au premier trimestre de 2015. Les exportations québécoises de biens vers l'étranger ont bondi de 9,4 % l'an dernier, mais elles ne progresseront cette année que de 0,8 % en raison d'un premier trimestre fort décevant. L'économie américaine s'est ressentie d'une grève dans les ports de la côte Ouest et du froid exceptionnel observé sur la côte Est cet hiver. Résultat : les exportations de biens et services du Québec, en hausse de 3,9 % en 2014, ne croîtront que de 1,1 % cette année, puis grimperont de 3,4 % en 2016.

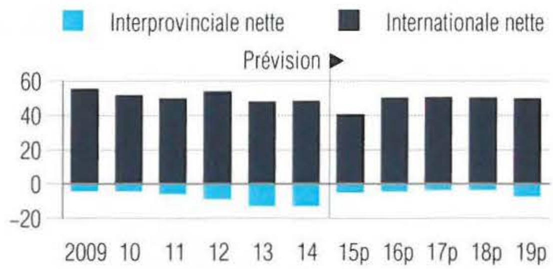
Le ralentissement des échanges commerciaux enregistré cette année se répercutera sur l'industrie manufacturière axée sur l'exportation, industrie qui ne gagnera que 1,7 % en 2015. La faible demande américaine amènera aussi les entreprises locales à retarder leurs grands projets d'investissement. La construction non résidentielle, comme les investissements liés au matériel et à l'outillage, inscriront cette année d'autres reculs de 8,2 % et 2,1 % respectivement, avant de se redresser en 2016; la première affichera une croissance de 2,4 %, l'autre de 2,3 %.

Contribution à la croissance du PIB réel du Québec
(pour 2015, industrie ou secteur, apport en points de pourcentage; PIB, en %)



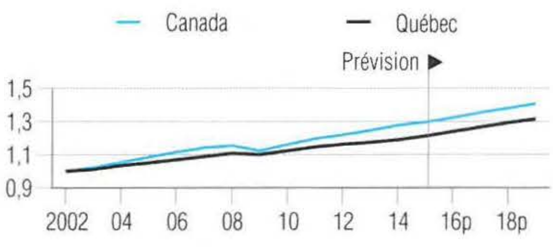
Nota : « Primaire » désigne l'ensemble des secteurs de l'agriculture, de la foresterie, de la pêche et du piégeage, et le secteur minier. « Industriel » désigne l'ensemble des secteurs de la fabrication, de la construction et des services d'utilité publics.
Sources : Le Conference Board du Canada; Statistique Canada.

Sources de migration
(migration nette, en milliers)



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

PIB réel de 2002 à 2019
(indice, 2002 = 1,0)



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

Par suite d'une progression de 1,1 % de l'emploi cette année, une croissance plus vive du revenu disponible des ménages aidera à stimuler le commerce de gros et de détail, qui croîtra de 2,6 %. Encore une fois, les dépenses de consommation seront déterminantes dans les résultats économiques de la province, tandis que les pouvoirs publics limitent à seulement 1,2 % la hausse des dépenses de programmes en 2015-2016.

LA REPRISE DES EXPORTATIONS CONNAÎT UNE STAGNATION TEMPORAIRE

Avec la reprise des exportations, qui ont inscrit une hausse de 3,9 %, la réduction du déficit commercial a représenté la moitié de la croissance du PIB réel de la province en 2014. Toutefois, l'hiver rigoureux a freiné l'économie américaine, de sorte que la demande finale des États-Unis a considérablement diminué au premier trimestre; de ce fait, les exportations québécoises de biens et services n'augmenteront que de 1,1 % cette année. Le repli de la demande finale des États-Unis, lié à une grève sans précédent des travailleurs portuaires de la côte Ouest et à un hiver exceptionnellement froid, sera passager. Cependant, la force du billet vert pourrait peser encore davantage que prévu sur l'activité économique américaine, les exportateurs des États-Unis vendant moins de produits à l'étranger parce que ceux-ci sont devenus relativement chers. Mais de solides facteurs économiques fondamentaux sont là pour permettre une croissance économique accrue au sud de la frontière et, à la lumière de statistiques encourageantes en matière d'emploi, l'économie américaine est en voie de progresser de 2,2 % en 2015. Cela, conjugué avec un huard assez loin de la parité, les perspectives du secteur des exportations sont encore plus favorables.

Les métaux de première transformation, les produits de l'aérospatiale, de l'électronique, du papier et du bois favoriseront la croissance des exportations québécoises. Si Bombardier connaît des difficultés dans la mise au point des appareils de la C Series et a récemment procédé à des mises à pied massives, d'autres entreprises affichent de meilleurs résultats. Ce sont des moteurs de Pratt & Whitney Canada construits à Mirabel qui équiperont les nouveaux jets d'affaires de Gulfstream et Héroux-Devtek a décroché le plus important contrat de son histoire en matière de trains d'atterrissage, ceux-là destinés aux nouveaux Boeing 777. La production se fera en partie à Laval. Les exportations du Québec devraient ainsi rebondir et croître de 3,4 % en 2016, puis de 3,2 % en 2017.

NOUVEAU RECUL DES INVESTISSEMENTS DES ENTREPRISES

Dans le contexte d'incertitude créé par l'effondrement des prix du pétrole brut, les entreprises canadiennes ont réduit leurs plans d'immobilisations au premier trimestre de 2015. Toutefois, l'indice de confiance du Conference Board du Canada montre que le climat s'est amélioré. Parmi les entreprises interrogées, le nombre de celles estimant que le moment n'est pas propice pour investir a considérablement diminué : elles étaient 27,3 % l'hiver dernier, mais seulement 12,9 % lors du dernier sondage. Parallèlement, les indicateurs relatifs aux pressions sur la capacité de production donnent des signaux mixtes : la proportion des entreprises répondant qu'elles fonctionnent à plein régime et près ou au-delà de leur capacité atteint désormais 45,1 %, contre 29,5 % dans le sondage précédent.

Le récent courant d'optimisme ne suffira cependant pas à contrebalancer la diminution des investissements des entreprises enregistrée au premier semestre de l'année. Ainsi, un repli de 2,9 % des investissements des entreprises est prévu dans la province en 2015. Un redressement est attendu l'an prochain, avec une hausse de 2,3 % des investissements en matériel et en outillage, et de 2,4 % dans la construction non résidentielle en 2016. Globalement, le Conference Board prévoit une progression de 0,5 % en 2016 et de 3,3 % des investissements réels des entreprises en 2017.

LES DÉPENSES DE CONSOMMATION SE MAINTIENNENT

Quoiqu'endettés, les consommateurs nourrissent la croissance économique par leurs dépenses. Ils devraient passer le relais aux entreprises, sauf que celles-ci ne sont pas prêtes et hésitent à accroître leur capacité. Les dépenses de consommation demeureront donc un pivot de l'économie du Québec en 2015, source de près de 75 % de la hausse du PIB réel cette année. En 2014, les dépenses de consommation finales des ménages ont fait preuve d'une surprenante résilience, affichant une hausse de 2 % malgré l'absence de création d'emploi et une progression du revenu disponible des ménages inférieure à la moyenne sur 10 ans. Mais pour continuer à dépenser, les consommateurs ont dû réduire leur épargne et recourir davantage au crédit. Le taux d'épargne dans la province a donc beaucoup baissé : 1,5 % en 2014 contre 2,7 % en 2013. Cette année, le marché du travail crée plus d'emplois. L'embauche devrait progresser de 1,1 %, ce qui devrait favoriser le pouvoir d'achat réel des ménages. De concert avec le prix peu élevé de l'essence, le recours accru au crédit et les transferts du gouvernement fédéral, cela permettra aux consommateurs de demeurer la locomotive de l'économie québécoise.

DIFFICULTÉS DANS L'INDUSTRIE DE LA CONSTRUCTION

Vu la baisse marquée des mises en chantier dans les immeubles à logements multiples, l'industrie québécoise de la construction se contractera pour une troisième année d'affilée. Ce recul de 1,3 % fera en sorte que quelque 9400 travailleurs perdront leur emploi dans le secteur de la construction en 2015. Cette conjoncture défavorable ne s'améliorera pas en 2016, si bien que le niveau d'embauche dans ce secteur aura baissé de 12,2 % par rapport au sommet de 2013. Les grands projets d'infrastructures, tels que le remplacement du pont Champlain et la reconstruction de l'échangeur Turcot, à Montréal, ne réussiront pas à faire contrepoids à la chute marquée des mises en chantier résidentielles et à la rareté des projets non résidentiels privés.

Risques conjoncturels

Court terme

- Une forte mobilisation des syndicats de la fonction publique pourrait perturber l'activité économique cet automne lors des négociations visant de nouvelles conventions collectives.

Moyen terme

- Si l'économie américaine, gênée par la hausse du billet vert, n'affiche pas les résultats escomptés, l'élan de reprise de l'industrie manufacturière du Québec pourrait être freiné.

Source : Le Conference Board du Canada.

Principaux indicateurs économiques : Québec

(Prévision en date du 16 juillet 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
PIB aux prix du marché	368 971	373 037	377 049	378 351	377 417	382 743	387 809	391 551	393 402	397 453	401 694	404 766	374 352	384 880	399 329
(en millions de dollars)	*0,9*	*1,1*	*1,1*	*0,3*	*–0,2*	*1,4*	*1,3*	*1,0*	*0,5*	*1,0*	*1,1*	*0,8*	*3,2*	*2,8*	*3,8*
PIB aux prix du marché	334 039	335 312	337 167	337 550	338 909	341 423	343 532	345 281	346 161	348 112	350 496	351 970	336 017	342 286	349 185
(en millions de dollars de 2007)	*0,2*	*0,4*	*0,6*	*0,1*	*0,4*	*0,7*	*0,6*	*0,5*	*0,3*	*0,6*	*0,7*	*0,4*	*1,4*	*1,9*	*2,0*
PIB aux prix de base	309 964	311 175	312 900	313 260	314 853	316 869	318 699	320 324	321 161	322 974	325 315	326 811	311 825	317 686	324 065
(en millions de dollars de 2007)	*0,2*	*0,4*	*0,6*	*0,1*	*0,5*	*0,6*	*0,6*	*0,5*	*0,3*	*0,6*	*0,7*	*0,5*	*1,4*	*1,9*	*2,0*
Indice des prix à la consommation	1,224	1,237	1,238	1,236	1,237	1,248	1,255	1,260	1,267	1,276	1,283	1,287	1,234	1,250	1,278
(2002 = 1,0)	*0,6*	*1,1*	*0,1*	*–0,1*	*0,1*	*0,8*	*0,6*	*0,4*	*0,6*	*0,7*	*0,5*	*0,3*	*1,4*	*1,3*	*2,2*
Déflateur implicite des prix —	1,105	1,113	1,118	1,121	1,114	1,121	1,129	1,134	1,136	1,142	1,146	1,150	1,114	1,124	1,144
PIB aux prix du marché (2007 = 1,0)	*0,7*	*0,7*	*0,5*	*0,2*	*–0,6*	*0,7*	*0,7*	*0,5*	*0,2*	*0,5*	*0,4*	*0,3*	*1,7*	*0,9*	*1,7*
Rémunération des employés	40,344	40,850	41,096	41,037	40,881	41,351	41,501	41,684	41,892	42,066	42,300	42,522	40,832	41,354	42,195
(en milliers de dollars)	*0,7*	*1,3*	*0,6*	*–0,1*	*–0,4*	*1,2*	*0,4*	*0,4*	*0,5*	*0,4*	*0,6*	*0,5*	*2,0*	*1,3*	*2,0*
Revenu primaire des ménages	251 584	253 349	255 089	255 714	257 896	260 111	262 187	264 088	266 541	268 629	270 987	273 286	253 934	261 070	269 861
(en millions de dollars)	*0,8*	*0,7*	*0,7*	*0,2*	*0,9*	*0,9*	*0,8*	*0,7*	*0,9*	*0,8*	*0,9*	*0,8*	*2,4*	*2,8*	*3,4*
Revenu disponible des ménages	220 872	222 738	224 591	225 516	227 277	228 921	232 402	232 571	233 959	235 821	237 893	240 062	223 429	230 293	236 934
(en millions de dollars)	*1,0*	*0,8*	*0,8*	*0,4*	*0,8*	*0,7*	*1,5*	*0,1*	*0,6*	*0,8*	*0,9*	*0,9*	*2,3*	*3,1*	*2,9*
Taux d'épargne nette des ménages (p. cent)	1,8	1,3	1,6	1,3	1,9	1,3	1,4	0,8	0,6	0,6	0,6	0,7	1,5	1,4	0,6
Population	8179	8191	8215	8236	8240	8245	8264	8283	8302	8320	8339	8357	8205	8258	8329
(en milliers)	*0,1*	*0,1*	*0,3*	*0,3*	*0,0*	*0,1*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,8*	*0,6*	*0,9*
Emploi	4066	4043	4056	4060	4090	4098	4108	4112	4124	4137	4149	4161	4056	4102	4143
(en milliers)	*–0,2*	*–0,5*	*0,3*	*0,1*	*0,7*	*0,2*	*0,2*	*0,1*	*0,3*	*0,3*	*0,3*	*0,3*	*–0,1*	*1,1*	*1,0*
Population active	4406	4390	4403	4394	4417	4440	4462	4475	4489	4499	4510	4520	4398	4449	4504
(en milliers)	*–0,1*	*–0,4*	*0,3*	*–0,2*	*0,5*	*0,5*	*0,5*	*0,3*	*0,3*	*0,2*	*0,2*	*0,2*	*0,1*	*1,1*	*1,3*
Participation au marché du travail	65,0	64,6	64,6	64,4	64,7	64,9	65,2	65,3	65,4	65,4	65,4	65,5	64,7	65,0	65,4
Taux de chômage (p. cent)	7,7	7,9	7,9	7,6	7,4	7,7	7,9	8,1	8,1	8,1	8,0	8,0	7,8	7,8	8,0
Ventes au détail	106 314	108 968	109 062	108 205	107 520	109 553	111 054	111 961	112 772	113 638	114 603	115 512	108 137	110 022	114 131
(en millions de dollars)	*–1,1*	*2,5*	*0,1*	*–0,8*	*–0,6*	*1,9*	*1,4*	*0,8*	*0,7*	*0,8*	*0,8*	*0,8*	*1,7*	*1,7*	*3,7*
Mises en chantier	38 874	39 173	37 181	40 012	28 222	35 801	32 893	32 683	31 880	31 635	31 429	31 364	38 810	32 400	31 577
(en milliers d'unités)	*–1,1*	*0,8*	*–5,1*	*7,6*	*–29,5*	*26,9*	*–8,1*	*–0,6*	*–2,5*	*–0,8*	*–0,7*	*–0,2*	*2,8*	*–16,5*	*–2,5*
Solde migratoire interprovincial (en milliers)	–10,2	–15,4	–20,1	–6,6	–10,4	–5,2	–3,0	–2,3	–3,6	–4,3	–4,5	–4,5	–13,1	–5,2	–4,2
Solde migratoire international (en milliers)	40,4	83,1	69,0	2,4	25,3	37,4	50,3	50,5	50,3	50,4	50,5	50,6	48,7	40,9	50,5

Les prévisions se trouvent dans la partie ombragée du tableau.
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).

Principaux indicateurs économiques : Québec suite

(Prévision en date du 16 juillet 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
PIB aux prix du marché	409 967	414 080	418 090	421 494	426 381	430 526	434 478	437 007	441 188	445 128	448 529	450 927	415 908	432 098	446 443
(en millions de dollars)	*1,3*	*1,0*	*1,0*	*0,8*	*1,2*	*1,0*	*0,9*	*0,6*	*1,0*	*0,9*	*0,8*	*0,5*	*4,2*	*3,9*	*3,3*
PIB aux prix du marché	354 409	355 849	357 748	359 678	361 596	362 991	364 493	366 113	367 378	368 635	369 843	370 954	356 921	363 798	369 202
(en millions de dollars de 2007)	*0,7*	*0,4*	*0,5*	*0,5*	*0,5*	*0,4*	*0,4*	*0,4*	*0,3*	*0,3*	*0,3*	*0,3*	*2,2*	*1,9*	*1,5*
PIB aux prix de base	329 194	330 658	332 549	334 470	336 378	337 806	339 337	340 980	342 295	343 605	344 872	346 051	331 718	338 625	344 206
(en millions de dollars de 2007)	*0,7*	*0,4*	*0,6*	*0,6*	*0,6*	*0,4*	*0,5*	*0,5*	*0,4*	*0,4*	*0,4*	*0,3*	*2,4*	*2,1*	*1,6*
Indice des prix à la consommation	1,294	1,304	1,310	1,314	1,321	1,331	1,337	1,341	1,349	1,358	1,365	1,369	1,305	1,333	1,360
(2002 = 1,0)	*0,6*	*0,7*	*0,5*	*0,3*	*0,6*	*0,7*	*0,5*	*0,3*	*0,6*	*0,7*	*0,5*	*0,3*	*2,1*	*2,1*	*2,1*
Déflateur implicite des prix —	1.157	1.164	1.169	1.172	1.179	1.186	1.192	1.194	1.201	1.208	1.213	1.216	1.165	1.188	1.209
PIB aux prix du marché (2007 = 1,0)	*0,6*	*0,6*	*0,4*	*0,3*	*0,6*	*0,6*	*0,5*	*0,1*	*0,6*	*0,5*	*0,4*	*0,2*	*1,9*	*1,9*	*1,8*
Rémunération des employés	42,762	43,017	43,273	43,523	43,769	44,091	44,345	44,636	44,926	45,210	45,502	45,799	43,144	44,210	45,359
(en milliers de dollars)	*0,6*	*0,6*	*0,6*	*0,6*	*0,6*	*0,7*	*0,6*	*0,7*	*0,7*	*0,6*	*0,6*	*0,7*	*2,2*	*2,5*	*2,6*
Revenu primaire des ménages	275 636	278 287	280 963	283 614	286 073	288 787	291 002	293 517	296 131	298 527	300 844	303 179	279 625	289 845	299 670
(en millions de dollars)	*0,9*	*1,0*	*1,0*	*0,9*	*0,9*	*0,9*	*0,8*	*0,9*	*0,9*	*0,8*	*0,8*	*0,8*	*3,6*	*3,7*	*3,4*
Revenu disponible des ménages	243 203	245 460	247 713	249 948	251 890	254 278	256 267	258 447	260 470	262 665	264 721	266 730	246 581	255 220	263 647
(en millions de dollars)	*1,3*	*0,9*	*0,9*	*0,9*	*0,8*	*0,9*	*0,8*	*0,9*	*0,8*	*0,8*	*0,8*	*0,8*	*4,1*	*3,5*	*3,3*
Taux d'épargne nette des ménages (p. cent)	0,9	0,9	0,9	0,9	0,9	0,9	1,0	0,9	1,0	1,1	1,1	1,2	0,9	0,9	1,1
Population	8 374	8 392	8 410	8 428	8 446	8 464	8 482	8 500	8 517	8 534	8 550	8 567	8 401	8 473	8 542
(en milliers)	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,9*	*0,9*	*0,8*
Emploi	4 175	4 189	4 203	4 217	4 226	4 234	4 241	4 250	4 258	4 267	4 273	4 279	4 196	4 238	4 269
(en milliers)	*0,3*	*0,3*	*0,3*	*0,3*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,1*	*0,1*	*1,3*	*1,0*	*0,7*
Population active	4 529	4 537	4 547	4 557	4 565	4 569	4 574	4 579	4 584	4 588	4 593	4 597	4 543	4 572	4 590
(en milliers)	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,8*	*0,6*	*0,4*
Participation au marché du travail	65,5	65,5	65,5	65,6	65,6	65,5	65,5	65,4	65,4	65,4	65,3	65,3	65,5	65,5	65,4
Taux de chômage (p. cent)	7,8	7,7	7,6	7,4	7,4	7,3	7,3	7,2	7,1	7,0	7,0	6,9	7,6	7,3	7,0
Ventes au détail	116 719	117 602	118 557	119 607	120 512	121 561	122 367	123 324	124 147	124 999	125 834	126 580	118 121	121 941	125 390
(en millions de dollars)	*1,0*	*0,8*	*0,8*	*0,9*	*0,8*	*0,9*	*0,7*	*0,8*	*0,7*	*0,7*	*0,7*	*0,6*	*3,5*	*3,2*	*2,8*
Mises en chantier	33 525	33 468	33 265	33 207	33 403	33 346	33 147	33 089	33 102	33 046	32 848	32 787	33 366	33 246	32 946
(en milliers d'unités)	*6,9*	*–0,2*	*–0,6*	*–0,2*	*0,6*	*–0,2*	*–0,6*	*–0,2*	*0,0*	*–0,2*	*–0,6*	*–0,2*	*5,7*	*–0,4*	*–0,9*
Solde migratoire interprovincial (en milliers)	–3,8	–3,8	–3,6	–3,5	–2,9	–3,3	–3,7	–4,5	–6,8	–7,4	–7,5	–7,7	–3,7	–3,6	–7,4
Solde migratoire international (en milliers)	50,9	51,0	51,0	50,9	50,6	50,5	50,4	50,3	50,2	50,1	50,1	50,0	50,9	50,5	50,1

Les prévisions se trouvent dans la partie ombragée du tableau.
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).

Fares Bounajm

Consumers Keep Economic Engine Humming

Highlights

- The contracting U.S. economy sends Ontario's economy off to a slow start this year.
- Exports will rebound in the second half of 2015 as the factors dragging them down abate.
- Tourism is experiencing a resurgence, fuelled by the low dollar and sporting events.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	2.3	2.0	2.3
Consumer Price Index	2.3	1.3	2.3
Household disposable income	3.3	4.0	3.1
Employment	0.8	0.8	1.2
Unemployment rate (level)	7.3	6.8	6.8
Retail sales	5.0	3.8	4.0
Wages and salaries per employee	2.2	2.6	2.0
Population	1.0	1.0	1.3

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

Government and Background Information

Premier	Kathleen Wynne
Next election	2018
Population (2015Q2)	13,750,073
Government balance (2015–16)	–$8.5 billion

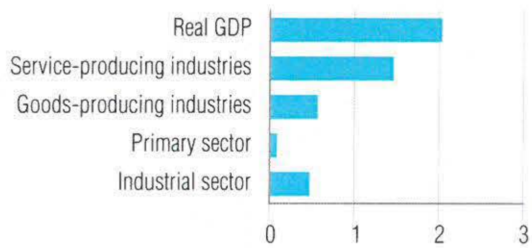
Sources: The Conference Board of Canada; Ontario Ministry of Finance; Statistics Canada.

Ontario's economy got off to a slow start this year as exports fell by an estimated 2.5 per cent in the first half of the year. Despite strong domestic demand, the province could not overcome the first-quarter contraction in the U.S. economy, which was caused by some temporary factors including a West Coast port dispute that disrupted trade and a large drop in energy investment. Ontario's disappointing trade performance will moderate the province's overall growth expectations in 2015 to a still-healthy 2 per cent. Most of this growth will be concentrated in the second half of the year as the U.S. economy shakes off the temporary factors that weighed on it earlier. This positive momentum will carry over to 2016 when real GDP is forecast to expand by 2.3 per cent.

Consumer spending has been quite robust, especially on durable goods as vehicle sales continue to set new records. Strong consumption is supported by healthy consumer confidence in the province, as evidenced by our consumer confidence survey that shows positive intentions on the questions regarding major purchases. Household consumption will gain 2.9 per cent in 2015 and 2.4 per cent in 2016.

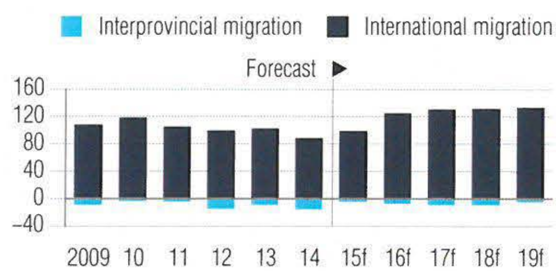
Although export growth has been disappointing so far this year, the weakness is expected to be temporary and better growth is forecast for the remainder of the year. Aside from the contraction in the U.S. economy, a temporary halt in production at motor vehicle plants in Windsor and Oakville led to a large drop in vehicle

Contributions to Ontario Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



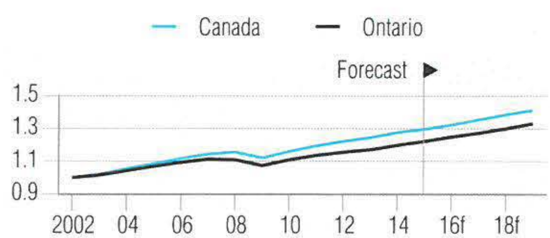
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

exports in the first quarter. With both plants back in full production, exports will accelerate over the remainder of the year, posting growth of 1.2 per cent. Buttressed by a weak Canadian dollar and stronger growth in the U.S. economy, the province's exports will enjoy strong growth of 4.2 per cent in 2015.

DOMESTIC DEMAND IS HOLDING THE FORT

Households remain the main driver of growth in Ontario's economy. Household consumption is set to grow by 2.9 per cent this year, with a 4.8 per cent increase in spending on durable goods. Motor vehicle sales continue to be outstanding. After breaking a new record in 2014, sales of new motor vehicles in Ontario are up 5.4 per cent year-over-year in the first five months of 2015 and are well on their way to posting a new all-time record. Strong sales have been fuelled in part by low interest rates and loose credit conditions.

Household consumption is forecast to remain robust in the near term. Families across Canada saw their Universal Child Care Benefit payments increase this year. Benefit increases were paid, beginning in July for benefits owed since January 2015, providing families with large retroactive lump sum payments. These tax benefits will help to keep household consumption in Ontario accelerating in the second half of the year. In 2016, household consumption is forecast to slow to a still-robust 2.4 per cent.

In addition to household consumption, domestic demand will be bolstered by substantial residential investment. Housing starts in Ontario are projected to jump by 8.5 per cent this year, encouraged by a healthy demand for housing and the two interest-rate cuts this year by the Bank of Canada. Non-residential investment will be soft, however, as weak demand from the U.S. is giving exporters little reason to invest in machinery and equipment and expand their productive capacity. In 2016, private non-residential investment is projected to grow by 2.4 per cent, as international demand improves.

EXPORTS TO ACCELERATE IN THE SECOND HALF

Despite the Canadian dollar trading at or near decade-lows in the first half of 2015, real exports have so far failed to gain any traction. In fact, they fell by an estimated 2.5 per cent over the first two quarters of the year. Exports were hurt by a slowing Chinese economy, which has reduced demand for metals, and a contracting U.S. economy, which suffered from a drop in energy investment and a labour dispute at West Coast ports that disrupted trade. In addition, a temporary halt in motor vehicle production has to shoulder much of the blame for this poor performance. According to *Automotive News*, 1.1 million vehicles were manufactured in Ontario in the first half of the year, down 6.8 per cent compared with the same period in 2014.[1] This decline was due to retooling and maintenance at both the Windsor and Oakville plants. With Ford's Oakville plant and Fiat Chrysler's Windsor plant having resumed production by the end of February and May, respectively, motor vehicle production in Ontario is back at full capacity. This, combined with a recovery in U.S. demand, will lead to a surge in the province's exports in the second half of the year, which are projected to grow by 1.2 per cent in 2015 and accelerate to 4.2 per cent in 2016.

TOURISM IS GETTING A SHOT IN THE ARM

When the Canadian dollar appreciated from a low of US$0.63 in 2002 to US$1.01 in 2011, Ontario's tourism sector was likely one of the biggest victims. The number of tourists entering Canada through Ontario dropped from 9.8 million in 2002 to 7.6 million in 2014. More dramatically, the number of tourists from the United States fell from an all-time high of 8.2 million to just 5.5 million during the same period. A report by the Canadian Tourism Research Institute (CTRI) noted that—adjusting for other factors such as travel trends, economic growth, and demographics—every 1 per cent increase in the value of the Canadian dollar has been associated with a 0.35 to 0.4 per cent drop in overnight trips from the United States.[2]

On the flip side, the tourism sector may prove to be one of the biggest winners from the loonie's recent change of fortune. Over the first five months of 2015, nearly 2.3 million tourists entered Ontario, up 7.5 per cent compared with last year. CTRI is forecasting a 4.5 per cent increase in overnight visits from the U.S. to Ontario in 2015, followed by a 1.6 per cent growth in 2016. Similarly, overnight visits from overseas to the province are projected to grow by 5.7 per cent and 4.1 per cent in 2015 and 2016, respectively. In addition to the falling loonie, tourists are being drawn by major sporting events, including the FIFA Women's World Cup and the Pan Am Games.

Forecast Risks

- Investment intentions in Statistics Canada's *Capital and Repair Expenditures Survey* showed double-digit growth in private non-residential construction in Ontario in 2015. This is much stronger than our forecast and, if it materializes, would boost the outlook.
- Motor vehicle sales in Ontario may be reaching a saturation point, limiting growth in household consumption in the medium term.

Source: The Conference Board of Canada.

1 Automotive News Data Center.

2 *Travel Exclusive: Key Trends for the Travel Industry* (Ottawa: The Conference Board of Canada, September–October 2011).

Key Economic Indicators: Ontario

Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	710,346	716,847	727,960	728,600	730,727	735,552	748,433	755,467	761,937	769,815	777,265	782,381	720,938	742,545	772,850
	1.1	*0.9*	*1.6*	*0.1*	*0.3*	*0.7*	*1.8*	*0.9*	*0.9*	*1.0*	*1.0*	*0.7*	*3.6*	*3.0*	*4.1*
GDP at market prices (2007 $ millions)	638,071	642,978	649,817	653,448	653,058	655,171	661,946	665,043	668,896	672,549	676,420	678,515	646,079	658,805	674,095
	0.2	*0.8*	*1.1*	*0.6*	*−0.1*	*0.3*	*1.0*	*0.5*	*0.6*	*0.5*	*0.6*	*0.3*	*2.2*	*2.0*	*2.3*
GDP at basic prices (2007 $ millions)	593,082	597,675	604,081	607,461	607,941	609,300	615,598	618,475	622,052	625,444	629,037	630,978	600,575	612,828	626,878
	0.3	*0.8*	*1.1*	*0.6*	*0.1*	*0.2*	*1.0*	*0.5*	*0.6*	*0.5*	*0.6*	*0.3*	*2.3*	*2.0*	*2.3*
Consumer price index (2002 = 1.0)	1.243	1.264	1.266	1.262	1.262	1.273	1.280	1.286	1.293	1.302	1.308	1.313	1.259	1.275	1.304
	0.9	*1.7*	*0.1*	*−0.3*	*0.0*	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*2.3*	*1.3*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.113	1.115	1.120	1.115	1.119	1.123	1.131	1.136	1.139	1.145	1.149	1.153	1.116	1.127	1.146
	1.0	*0.1*	*0.5*	*−0.5*	*0.4*	*0.3*	*0.7*	*0.5*	*0.3*	*0.5*	*0.4*	*0.3*	*1.4*	*1.0*	*1.7*
Wages and salary per employee ($ 000s)	47.337	47.752	48.164	48.145	48.924	48.900	49.123	49.418	49.664	49.929	50.179	50.446	47.849	49.091	50.055
	0.8	*0.9*	*0.9*	*0.0*	*1.6*	*0.0*	*0.5*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*2.2*	*2.6*	*2.0*
Primary household income ($ millions)	484,241	488,400	492,617	495,586	504,173	506,149	510,432	514,590	519,471	524,103	528,448	532,908	490,211	508,836	526,233
	1.2	*0.9*	*0.9*	*0.6*	*1.7*	*0.4*	*0.8*	*0.8*	*0.9*	*0.9*	*0.8*	*0.8*	*3.5*	*3.8*	*3.4*
Household disposable income ($ millions)	420,990	423,679	427,575	429,557	438,420	439,358	445,490	446,918	450,716	454,581	457,973	461,294	425,450	442,547	456,141
	1.1	*0.6*	*0.9*	*0.5*	*2.1*	*0.2*	*1.4*	*0.3*	*0.8*	*0.9*	*0.7*	*0.7*	*3.3*	*4.0*	*3.1*
Household net savings rate (per cent)	4.2	2.9	2.7	2.4	3.9	2.7	2.8	2.2	2.0	2.0	2.1	2.1	3.0	2.9	2.1
Population (000s)	13615	13640	13679	13730	13734	13750	13840	13880	13920	13960	13999	14040	13666	13801	13980
	0.1	*0.2*	*0.3*	*0.4*	*0.0*	*0.1*	*0.7*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.0*	*1.3*
Employment (000s)	6856	6869	6879	6904	6896	6922	6946	6960	6981	7004	7025	7046	6877	6931	7014
	0.1	*0.2*	*0.1*	*0.4*	*−0.1*	*0.4*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.8*	*0.8*	*1.2*
Labour force (000s)	7406	7410	7426	7419	7406	7411	7447	7476	7494	7520	7540	7561	7415	7435	7529
	0.0	*0.1*	*0.2*	*−0.1*	*−0.2*	*0.1*	*0.5*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.3*	*1.3*
Labour force participation rate (per cent)	66.0	65.8	65.8	65.6	65.3	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.8	65.2	65.2
Unemployment rate (per cent)	7.4	7.3	7.4	6.9	6.9	6.6	6.7	6.9	6.8	6.9	6.8	6.8	7.3	6.8	6.8
Retail sales ($ millions)	170,948	176,477	179,160	180,290	178,572	183,179	185,072	187,057	188,846	190,283	191,426	192,323	176,719	183,470	190,720
	0.6	*3.2*	*1.5*	*0.6*	*−1.0*	*2.6*	*1.0*	*1.1*	*1.0*	*0.8*	*0.6*	*0.5*	*5.0*	*3.8*	*4.0*
Housing starts (units, 000s)	54,113	64,522	58,629	59,272	55,610	67,721	66,833	66,448	64,630	64,522	64,328	64,418	59,134	64,153	64,475
	−15.1	*19.2*	*−9.1*	*1.1*	*−6.2*	*21.8*	*−1.3*	*−0.6*	*−2.7*	*−0.2*	*−0.3*	*0.1*	*−3.2*	*8.5*	*0.5*
Net interprovincial migration (000s)	−18.6	−31.8	−2.4	−9.7	−13.8	3.1	−2.8	−4.7	−6.7	−7.5	−7.7	−8.0	−15.6	−4.5	−7.5
Net international migration (000s)	89.3	138.3	147.1	−19.2	53.4	105.4	118.2	120.7	122.4	124.4	126.2	127.8	88.9	99.4	125.2

Shaded 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: Ontario cont'd

Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	790,396	798,556	806,416	813,200	823,341	832,161	840,623	846,555	856,386	865,880	874,553	881,520	802,142	835,670	869,585
	1.0	*1.0*	*1.0*	*0.8*	*1.2*	*1.1*	*1.0*	*0.7*	*1.2*	*1.1*	*1.0*	*0.8*	*3.8*	*4.2*	*4.1*
GDP at market prices (2007 $ millions)	681,572	684,551	688,324	692,232	696,535	699,918	703,513	707,518	711,407	715,375	719,422	723,474	686,670	701,871	717,420
	0.5	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*1.9*	*2.2*	*2.2*
GDP at basic prices (2007 $ millions)	633,811	636,572	640,073	643,700	647,689	650,831	654,171	657,895	661,514	665,208	668,978	672,754	638,539	652,647	667,114
	0.4	*0.4*	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*1.9*	*2.2*	*2.2*
Consumer price index (2002 = 1.0)	1.320	1.330	1.336	1.340	1.348	1.357	1.364	1.368	1.376	1.386	1.392	1.397	1.331	1.359	1.388
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.160	1.167	1.172	1.175	1.182	1.189	1.195	1.197	1.204	1.210	1.216	1.218	1.168	1.191	1.212
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.8*
Wages and salary per employee ($ 000s)	50.752	51.110	51.434	51.727	52.014	52.296	52.609	52.939	53.292	53.671	54.021	54.379	51.256	52.465	53.841
	0.6	*0.7*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*2.4*	*2.4*	*2.6*
Primary household income ($ millions)	536,968	542,544	547,638	552,456	558,027	562,990	568,358	574,087	580,473	586,520	592,590	598,730	544,902	565,865	589,578
	0.8	*1.0*	*0.9*	*0.9*	*1.0*	*0.9*	*1.0*	*1.0*	*1.1*	*1.0*	*1.0*	*1.0*	*3.5*	*3.8*	*4.2*
Household disposable income ($ millions)	464,355	468,475	472,220	475,695	479,460	483,353	487,646	492,167	497,122	502,350	507,581	512,856	470,186	485,656	504,977
	0.7	*0.9*	*0.8*	*0.7*	*0.8*	*0.8*	*0.9*	*0.9*	*1.0*	*1.1*	*1.0*	*1.0*	*3.1*	*3.3*	*4.0*
Household net savings rate (per cent)	2.3	2.4	2.4	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.6	2.7	2.3	2.4	2.6
Population (000s)	14,081	14,122	14,163	14,204	14,247	14,288	14,330	14,372	14,412	14,454	14,497	14,540	14,142	14,309	14,476
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.2*	*1.2*	*1.2*
Employment (000s)	7,063	7,086	7,105	7,123	7,146	7,170	7,196	7,225	7,253	7,280	7,310	7,341	7,094	7,184	7,296
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.1*	*1.3*	*1.6*
Labour force (000s)	7,581	7,604	7,625	7,640	7,655	7,663	7,675	7,690	7,711	7,734	7,761	7,786	7,612	7,671	7,748
	0.3	*0.3*	*0.3*	*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*0.8*	*1.0*
Labour force participation rate (per cent)	65.2	65.2	65.2	65.1	65.1	64.9	64.8	64.8	64.8	64.8	64.8	64.8	65.2	64.9	64.8
Unemployment rate (per cent)	6.8	6.8	6.8	6.8	6.7	6.4	6.2	6.0	5.9	5.9	5.8	5.7	6.8	6.3	5.8
Retail sales ($ millions)	192,624	193,777	194,864	196,019	197,365	198,583	199,985	201,546	203,248	204,953	206,750	208,452	194,321	199,370	205,850
	0.2	*0.6*	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*1.9*	*2.6*	*3.3*
Housing starts (units, 000s)	58,875	60,948	62,218	65,406	66,800	68,416	69,750	73,008	77,177	80,574	82,905	85,313	61,862	69,493	81,492
	–8.6	*3.5*	*2.1*	*5.1*	*2.1*	*2.4*	*2.0*	*4.7*	*5.7*	*4.4*	*2.9*	*2.9*	*–4.1*	*12.3*	*17.3*
Net interprovincial migration (000s)	–8.8	–9.1	–9.1	–9.2	–9.9	–9.9	–9.2	–8.3	–5.8	–4.7	–3.9	–3.2	–9.1	–9.3	–4.4
Net international migration (000s)	129.8	130.9	131.6	132.0	130.8	130.9	131.3	131.8	133.0	133.5	134.0	134.4	131.1	131.2	133.7

Shaded 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.

Lois Mainville

Manitoba's Economy on Solid Ground

Highlights

- All key sectors of Manitoba's economy are experiencing sound growth.
- Strong gains are expected in manufacturing sector.
- The healthy economy is expected to boost employment and consumer spending.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.1	2.4	2.5
Consumer Price Index	1.8	1.4	2.3
Household disposable income	2.6	3.3	3.2
Employment	0.1	1.7	1.4
Unemployment rate (level)	5.4	5.5	5.1
Retail sales	4.3	1.5	3.8
Wages and salaries per employee	2.9	0.9	2.2
Population	1.3	1.2	1.3

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

Government and Background Information

Premier	Greg Selinger
Next election	April 19, 2016
Population (2015Q2)	1,292,151
Government balance (2015–16)	–$422 million

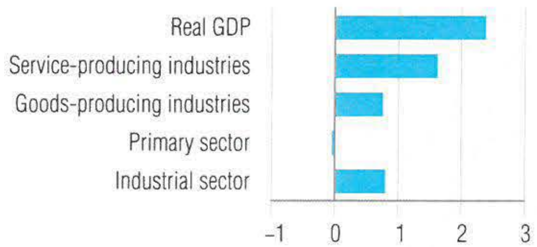
Sources: The Conference Board of Canada; Manitoba Budget Documents.

Manitoba's economy is on solid ground with gains expected across key sectors over the next two years. Real GDP growth is projected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping Manitoba among the provincial growth leaders.

Solid gains are forecast in manufacturing, agriculture and construction. Because of the correction in oil prices, the mining sector is not expected to grow in 2015 and will advance only moderately in 2016. Metal ore production will perform better with the opening of two new mines and steady production levels in existing mines.

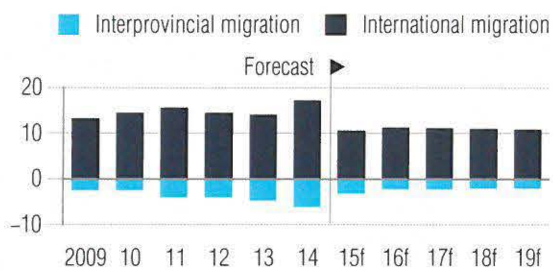
Increased activity is anticipated on all fronts for Manitoba's manufacturing sector, thanks to a rebounding U.S. economy. Growth in manufacturing is projected to hit 4.5 per cent in 2015 and 2.3 per cent in 2016. The agriculture sector is expected to rebound this year with 3.9 per cent growth as the drought and dry weather in neighbouring Saskatchewan and Alberta have not affected Manitoba too much. In addition, construction is ramping up across the province with the provincial government's infrastructure plan and Manitoba Hydro projects breaking ground

Contributions to Manitoba Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



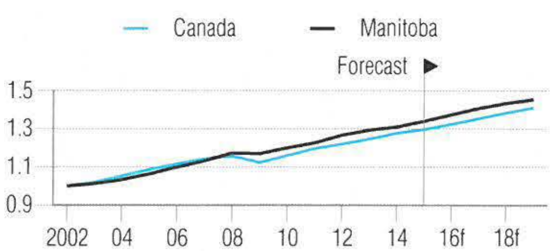
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

The gains in the goods-producing industries are expected to be reflected in the services sectors. Employment is forecast to rise by an average of 1.4 per cent over the next two years. Also foreseen is a decrease in the province's unemployment rate—from 5.5 per cent in 2015 to an average of 5.1 per cent over the medium term. With stronger job creation, household disposable income will spur household consumption expenditures, boosting wholesale and retail trade in the province by 3.6 per cent in 2016 and 2.9 per cent in 2016.

METAL MINING REACHING TARGET PRODUCTION LEVELS

Metal mining is expected to grow 8.4 per cent in 2015 as production is ramping up at two new mines in the province, the Reed copper mine (a joint venture between Hudbay Minerals and VMS Ventures) and the Lalor copper-zinc-gold mine (Hudbay Minerals). Growth in the sector is projected to slow to 0.7 per cent in 2016 as the two new mines reach steady production levels.

MANUFACTURING GROWING ON ALL FRONTS

The manufacturing sector is projected to be one of the strongest performers in Manitoba in 2015 with growth of 4.5 per cent, followed by a 2.3 per cent increase in 2016.

U.S. demand for heavy-duty buses is helping boost output in manufacturing. New Flyer Industries have recently announced orders of 218 buses for Orange County and 138 buses for King County (Seattle Metro Area). The Winnipeg-based company is also working on a large order for the New York City Transit Authority. As well, Motor Coach Industries recently made a $395-million deal to deliver 772 commuter coaches to New Jersey Transit over the next six years.

In the aerospace industry, StandardAero recently announced that it will expand its Winnipeg operations by adding new strategic business lines. The multi-million-dollar investment will offer engine repair services that are currently unavailable on the market and that will not duplicate work now being done south of the border. Operations on certain lines are expected to begin production at the end of the year with the expansion slated to be completed in 2016.

CONSTRUCTION BOOST ACROSS THE PROVINCE

Construction should keep the province's economy on a solid track with growth in the sector anticipated at 3.1 per cent for 2015, 6 per cent for 2016, and 5.3 per cent for 2017. The province's five-year infrastructure plan is currently in full swing. The completion of the $5.5-billion investment in roads and bridges, municipal infrastructure, public transit, and flood protection is projected in about four years (2019). Two large Manitoba Hydro projects are also contributing positively to the sector's outlook over the medium term. Construction on the Keeyask Generating Station began last summer; this $6.5-billion project has a target in-service date of 2019. Work is forecast to break ground this year on the Bipole III Transmission Reliability Project. This project, expected to improve the reliability of Manitoba's power system, has an in-service date of 2018.

Housing starts are projected to decline this year but to pick up again in 2016 when the housing market levels off. In Winnipeg, strong population growth has recently spurred quite a bit of building activity. However, there is a high inventory of unsold units and suppliers are working on clearing the backlog. Over the medium term, demand for housing is expected to increase due to strong population growth, especially from international migration, as well as historically low interest rates.

AGRICULTURE ON THE REBOUND

Following a difficult 2014 due to bad weather conditions, agriculture is projected to rebound in Manitoba with growth expected at 3.8 per cent for 2015 and 1.9 per cent for 2016. The drought currently affecting Saskatchewan and Alberta has not hit Manitoba. Good weather conditions so far this year should set the stage for a great crop year in Manitoba. The province will also benefit from higher commodity prices due to extreme weather conditions affecting crops in various markets. The grain transportation backlog on the railways from the bumper crop of 2013 has for the most part been cleared and that will help producers move products more easily than in the past few years.

Various developments on international markets may affect the medium-term outlook for agriculture. Although the U.S. House of Representatives has voted to repeal Country of Origin Labelling (COOL) regulations, the Senate has introduced a bill calling for voluntary labelling at the dissatisfaction of Canadian stakeholders. Unless COOL is fully repealed, the Canadian government is threatening to impose retaliatory tariffs against the U.S. If COOL is repealed, Canadian producers should become more competitive on the U.S. market as production costs will be lower for agricultural producers venturing on that market.

Forecast Risks

Short term
- Weather conditions across North America may cause commodity prices to rise due to supply constraints, benefiting Manitoba's agricultural sector that might experience a bumper crop year.

Medium term
- If Hudbay Minerals refurbishes the recently acquired New Britannia mill, metal mining output could increase further.

Source: The Conference Board of Canada.

The Canada–Korea Free Trade Agreement, which came into effect earlier this year, is expected to have positive supply-chain effects in Asia. On the downside, the Russian ban on Canadian agricultural imports (related to the Ukrainian conflict) probably will be extended past its August expiry date.

SERVICES AND DOMESTIC DEMAND

The healthy gains in the province's goods-producing industries are forecast to be reflected in the services sectors over the next two years. Looked-for expansions include the following: transportation and warehousing, 3.9 per cent in 2015 and 3.1 per cent in 2016; wholesale and retail trade, 3.6 per cent and 2.9 per cent in 2015 and 2016, respectively.

Labour demand will be strong. Growth in employment is projected to average 1.4 percent annually over the next two years. The growth in employment and household disposable income will support increases of 0.9 per cent in 2015 and 2.4 per cent in 2016 in real household consumption with the fastest growth in the consumption of semi-durable goods.

Key Economic Indicators: Manitoba

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	62,275	62,371	63,761	63,420	64,160	65,329	66,247	66,979	67,318	67,986	68,721	69,218	62,957	65,679	68,311
	0.5	*0.2*	*2.2*	*-0.5*	*1.2*	*1.8*	*1.4*	*1.1*	*0.5*	*1.0*	*1.1*	*0.7*	*2.7*	*4.3*	*4.0*
GDP at market prices (2007 $ millions)	56,745	56,699	57,784	57,216	57,947	58,282	58,647	59,027	59,338	59,699	60,170	60,456	57,111	58,476	59,916
	0.1	*-0.1*	*1.9*	*-1.0*	*1.3*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.8*	*0.5*	*1.1*	*2.4*	*2.5*
GDP at basic prices (2007 $ millions)	52,535	52,492	53,496	52,971	53,648	53,959	54,295	54,647	54,933	55,266	55,700	55,962	52,874	54,137	55,465
	0.1	*-0.1*	*1.9*	*-1.0*	*1.3*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.8*	*0.5*	*1.1*	*2.4*	*2.5*
Consumer price index (2002 = 1.0)	1.243	1.259	1.257	1.252	1.254	1.269	1.277	1.282	1.289	1.298	1.305	1.309	1.253	1.271	1.300
	0.6	*1.3*	*-0.1*	*-0.5*	*0.2*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.8*	*1.4*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.097	1.100	1.103	1.108	1.107	1.121	1.130	1.135	1.134	1.139	1.142	1.145	1.102	1.123	1.140
	0.3	*0.2*	*0.3*	*0.5*	*-0.1*	*1.2*	*0.8*	*0.5*	*0.0*	*0.4*	*0.3*	*0.2*	*1.5*	*1.9*	*1.5*
Wages and salary per employee ($ 000s)	42.918	43.539	43.668	43.100	43.436	43.608	43.803	43.993	44.235	44.518	44.810	45.087	43.306	43.710	44.662
	-0.2	*1.4*	*0.3*	*-1.3*	*0.8*	*0.4*	*0.4*	*0.4*	*0.5*	*0.6*	*0.7*	*0.6*	*2.9*	*0.9*	*2.2*
Primary household income ($ millions)	40,248	40,717	41,077	41,050	41,826	41,944	42,234	42,563	43,013	43,470	43,933	44,402	40,773	42,141	43,705
	0.0	*1.2*	*0.9*	*-0.1*	*1.9*	*0.3*	*0.7*	*0.8*	*1.1*	*1.1*	*1.1*	*1.1*	*2.6*	*3.4*	*3.7*
Household disposable income ($ millions)	35,862	36,192	36,456	36,374	37,130	37,171	37,642	37,721	38,031	38,425	38,827	39,240	36,221	37,416	38,631
	0.1	*0.9*	*0.7*	*-0.2*	*2.1*	*0.1*	*1.3*	*0.2*	*0.8*	*1.0*	*1.0*	*1.1*	*2.6*	*3.3*	*3.2*
Household net savings rate (per cent)	0.2	-0.3	-0.4	-1.4	1.3	0.0	0.2	-0.5	-0.7	-0.7	-0.6	-0.6	-0.5	0.3	-0.6
Population (000s)	1273	1277	1282	1286	1290	1292	1296	1300	1305	1309	1313	1317	1280	1295	1311
	0.3	*0.3*	*0.4*	*0.3*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.2*	*1.3*
Employment (000s)	623	623	627	634	637	637	637	639	642	645	648	652	627	638	647
	0.3	*-0.1*	*0.7*	*1.1*	*0.5*	*0.0*	*0.1*	*0.3*	*0.4*	*0.5*	*0.5*	*0.5*	*0.1*	*1.7*	*1.4*
Labour force (000s)	659	659	663	668	675	674	674	675	678	680	682	686	662	674	681
	0.0	*-0.1*	*0.6*	*0.8*	*1.0*	*-0.2*	*0.0*	*0.2*	*0.4*	*0.3*	*0.4*	*0.5*	*0.1*	*1.8*	*1.0*
Labour force participation rate (per cent)	67.9	67.6	67.8	68.2	68.6	68.4	68.3	68.2	68.2	68.2	68.3	68.4	67.8	68.4	68.3
Unemployment rate (per cent)	5.5	5.5	5.4	5.2	5.6	5.5	5.4	5.3	5.3	5.1	5.0	5.0	5.4	5.5	5.1
Retail sales ($ millions)	17,774	17,990	18,172	18,201	17,936	18,261	18,431	18,588	18,746	18,916	19,085	19,239	18,034	18,304	18,996
	2.2	*1.2*	*1.0*	*0.2*	*-1.5*	*1.8*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*	*0.8*	*4.3*	*1.5*	*3.8*
Housing starts (units, 000s)	4,077	7,162	8,488	5,153	5,080	5,128	6,387	6,658	6,595	6,650	6,675	6,731	6,220	5,813	6,663
	-44.8	*75.7*	*18.5*	*-39.3*	*-1.4*	*0.9*	*24.6*	*4.2*	*-1.0*	*0.8*	*0.4*	*0.8*	*-16.7*	*-6.5*	*14.6*
Net interprovincial migration (000s)	-5.7	-5.5	-9.5	-4.2	-6.2	-2.5	-2.3	-2.3	-2.4	-2.4	-2.3	-2.3	-6.2	-3.3	-2.3
Net international migration (000s)	15.1	21.1	19.5	12.7	11.4	7.7	11.6	11.5	11.3	11.3	11.2	11.1	17.1	10.5	11.2

Shaded 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: Manitoba cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	70,068	70,771	71,458	72,062	73,067	73,780	74,405	74,751	75,354	75,926	76,357	76,593	71,090	74,001	76,058
	1.2	*1.0*	*1.0*	*0.8*	*1.4*	*1.0*	*0.8*	*0.5*	*0.8*	*0.8*	*0.6*	*0.3*	*4.1*	*4.1*	*2.8*
GDP at market prices (2007 $ millions)	60,991	61,270	61,602	61,926	62,189	62,407	62,629	62,873	63,067	63,299	63,516	63,727	61,447	62,525	63,402
	0.9	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*2.6*	*1.8*	*1.4*
GDP at basic prices (2007 $ millions)	56,454	56,711	57,016	57,314	57,555	57,755	57,960	58,186	58,366	58,583	58,785	58,984	56,874	57,864	58,679
	0.9	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*2.5*	*1.7*	*1.4*
Consumer price index (2002 = 1.0)	1.316	1.326	1.332	1.336	1.344	1.353	1.360	1.364	1.372	1.381	1.388	1.392	1.328	1.355	1.383
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.149	1.155	1.160	1.164	1.175	1.182	1.188	1.189	1.195	1.199	1.202	1.202	1.157	1.184	1.200
	0.3	*0.5*	*0.4*	*0.3*	*1.0*	*0.6*	*0.5*	*0.1*	*0.5*	*0.4*	*0.2*	*0.0*	*1.5*	*2.3*	*1.4*
Wages and salary per employee ($ 000s)	45.350	45.645	45.914	46.179	46.440	46.723	46.987	47.243	47.521	47.808	48.093	48.386	45.772	46.848	47.952
	0.6	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*2.5*	*2.4*	*2.4*
Primary household income ($ millions)	44,807	45,309	45,711	46,102	46,509	46,868	47,227	47,583	47,957	48,325	48,700	49,081	45,482	47,047	48,516
	0.9	*1.1*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*4.1*	*3.4*	*3.1*
Household disposable income ($ millions)	39,667	40,112	40,461	40,801	41,114	41,450	41,780	42,101	42,406	42,753	43,095	43,435	40,261	41,611	42,922
	1.1	*1.1*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.8*	*0.8*	*0.8*	*4.2*	*3.4*	*3.1*
Household net savings rate (per cent)	-0.4	-0.3	-0.3	-0.4	-0.4	-0.3	-0.3	-0.3	-0.3	-0.2	-0.1	0.0	-0.4	-0.3	-0.1
Population (000s)	1,321	1,326	1,330	1,334	1,338	1,342	1,346	1,351	1,355	1,359	1,363	1,367	1,328	1,344	1,361
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.3*	*1.2*
Employment (000s)	655	658	659	661	661	662	663	664	664	664	665	666	658	662	665
	0.5	*0.5*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.1*	*0.1*	*1.7*	*0.7*	*0.4*
Labour force (000s)	689	693	694	696	697	698	699	700	700	701	702	703	693	698	702
	0.5	*0.5*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.2*	*0.0*	*0.1*	*0.1*	*0.2*	*1.7*	*0.8*	*0.5*
Labour force participation rate (per cent)	68.5	68.7	68.6	68.6	68.5	68.4	68.3	68.2	68.0	67.9	67.8	67.7	68.6	68.4	67.9
Unemployment rate (per cent)	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.0	5.1	5.2
Retail sales ($ millions)	19,354	19,510	19,620	19,745	19,858	19,965	20,066	20,167	20,250	20,347	20,452	20,545	19,557	20,014	20,399
	0.6	*0.8*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.4*	*0.5*	*0.5*	*0.5*	*3.0*	*2.3*	*1.9*
Housing starts (units, 000s)	6,754	6,810	6,733	6,688	6,713	6,669	6,592	6,548	6,574	6,632	6,554	6,612	6,746	6,630	6,593
	0.3	*0.8*	*-1.1*	*-0.7*	*0.4*	*-0.7*	*-1.1*	*-0.7*	*0.4*	*0.9*	*-1.2*	*0.9*	*1.3*	*-1.7*	*-0.6*
Net interprovincial migration (000s)	-2.3	-2.3	-2.3	-2.2	-2.2	-2.2	-2.2	-2.2	-2.1	-2.1	-2.1	-2.1	-2.3	-2.2	-2.1
Net international migration (000s)	11.1	11.1	11.1	11.0	11.0	11.0	11.0	10.9	10.9	10.8	10.8	10.8	11.1	11.0	10.8

Shaded 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

Lois Mainville

Weather Woes Adding to a Difficult Year

Highlights

- The economy is expected to contract in 2015, due to a bad year for the oil industry and the agriculture sector.
- The construction sector is set to do well next year.
- A better outlook exists for the economy for 2016.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.4	–0.2	2.6
Consumer Price Index	2.4	1.7	2.3
Household disposable income	1.7	3.5	3.0
Employment	1.0	0.5	0.9
Unemployment rate (level)	3.8	4.7	4.7
Retail sales	4.6	–1.2	3.4
Wages and salaries per employee	3.3	2.4	1.9
Population	1.7	1.3	1.6

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

Government and Background Information

Premier	Brad Wall
Next election	April 4, 2016
Population (2015Q2)	1,134,402
Government balance (2015–16)	$107 million

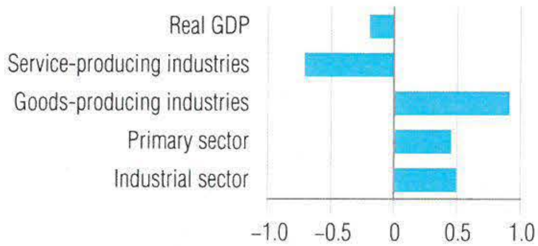
Sources: Saskatchewan Budget Documents.

Faced with a severe correction in the energy sector, economic growth will turn negative in Saskatchewan this year. Further weighing down economic growth are the drought conditions for the agriculture sector, and rising uranium and potash production will not be enough to keep real GDP growth in positive territory. Construction is also expected to cool off this year. Overall, a decline of 0.2 per cent in real GDP is foreseen this year.

Another correction in the energy sector does not appear likely in 2016 and, with uranium and potash production continuing to increase, the economy is forecast to perform better in 2016. Construction will also pick up again with projects in the mining and energy sector. Overall, Saskatchewan's economy is projected to grow by 2.6 per cent in 2016.

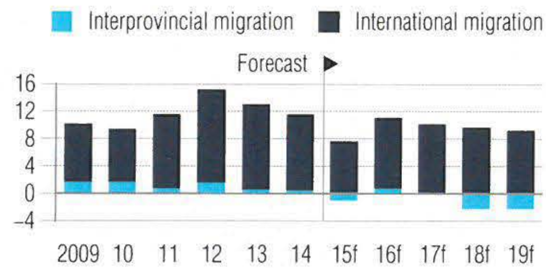
The weak economy slowed down job creation. Employment will rise by only 0.5 per cent this year but will expand by 0.9 per cent in 2016. The unemployment rate is expected to increase to 4.7 per cent, up from 3.5 per cent in 2014. Despite this rise, the province's unemployment rate will remain the lowest in Canada. The economic slowdown of 2015 and the rebound of 2016 will be mirrored in household consumption patterns: weakness this year and stronger growth next year.

Contributions to Saskatchewan Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



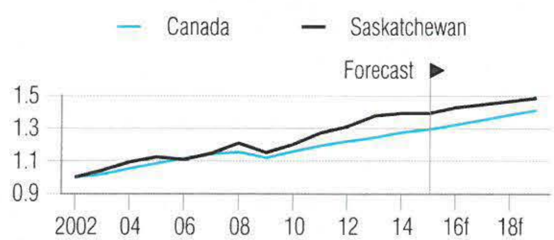
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

POTASH AND URANIUM TO TEMPER OIL PRICE IMPACTS

The outlook for the mining sector remains mixed with potash and uranium tempering the effects of the drop in oil prices. Overall, mining is expected to contract by 1.4 per cent this year.

Metal mining however, is looking for an increase of 12.8 per cent this year and 9.6 per cent in 2016. Increased supply from Cameco's Cigar Lake uranium mine, in addition to demand from China, India, and Japan, is contributing to the bright outlook for the sector. Non-metal mining is also forecast to perform well with growth of 11.1 per cent this year and 6.1 per cent in 2016, thanks to increased production from recent expansions at Agrium's Vanscoy and PotashCorp's Rocanville mines. Production at the K+S Legacy mine is expected to begin at the end of 2016.

But mineral fuels are weighing down the mining outlook for 2015, due to the steep decline in oil prices. As the number of wells drilled during the winter drilling season was down, oil production will slow this year and the effects will be felt throughout the industry's supply chain. Although it is not anticipated that oil prices will return to their previous three-digit levels, a slight increase in prices appears to be in the cards. Growth in mineral fuels should be 1.3 per cent in 2016 while overall growth in the mining sector is expected to reach 2.4 per cent in 2016.

DROUGHT CAUSING LOSSES IN AGRICULTURE

Seeding is currently well above the five-year average, as producers took advantage of the ideal favourable spring weather. However, hot and dry weather has thrown parts of Saskatchewan and Alberta into a drought. The anticipation of lower crop yields is not only affecting crop production but is also creating ripple effects throughout the agricultural sector. For example, as a cost-cutting measure, livestock producers might have to start selling off animals as feed is now more expensive because supply constraints are expected to lift commodity prices.

The highly anticipated rebound in agriculture, following a difficult 2014, is now projected to become a 2.4 per cent loss for 2015.

But the agriculture sector is expected to bounce back next year with a 2.1 per cent growth if, of course, more normal weather occurs. International trade should also contribute to the sector's recovery over the medium term. The U.S. House of Representatives has voted to repeal Country of Origin Labelling (COOL) and Senate approval is pending. If COOL is repealed, Canadian products should become more competitive on the U.S. market as production costs will be lower for Canadian agricultural producers venturing into the American market. It is anticipated that the Canada–Korea Free Trade Agreement, which came into effect earlier this year, will have positive supply-chain effects in Asia.

CONSTRUCTION OUTCOME DEPENDENT ON MINING INVESTMENT DECISIONS

Construction is forecast to decline by 7.6 per cent this year as work on the Cigar Lake uranium mine and the Rocanville and Vanscoy potash mine expansions are now complete and investment in the energy sector is much weaker. Although work is ongoing on the K+S Legacy potash mine, this project is not enough to lift growth in the construction sector into positive territory. Projects currently in the feasibility stage or different stages of approval—such as the Orion diamond mine (Star Gold), Kronau potash mine (Vale), Jansen potash mine (BHP Billiton), and Energy East pipeline project (Enbridge)—are expected to determine the outcome of the construction sector over the medium term and could boost growth above what we are currently forecasting.

Housing starts are projected to decline this year as Regina's and Saskatoon's hot housing markets are expected to level off. Strong pent-up demand has occasioned a lot of building in the two cities, resulting in a high inventory of unsold units. Housing starts are forecast to pick up again in 2016 as the housing market should be more balanced with the uptick in the economy.

Government investment is expected to contribute positively to the construction outlook over the next few years. In the most recent budget, the provincial government presented a four-year, $5.8-billion infrastructure plan to sustain growth in the province. The largest infrastructure plan in the province's history includes investments in transportation infrastructure (including the Regina Bypass), municipal infrastructure, education, health care, and government services. Overall, the construction sector is looking for an increase of 7.4 per cent in 2016.

DOMESTIC DEMAND MIRRORS THE ECONOMY'S STATUS

The downturn in the province's major sectors will cause employment growth to slow this year to just 0.5 per cent. With activity picking up again in major sectors in 2016, employment is expected to grow by 0.9 per cent. The unemployment rate will increase to 4.7 per cent this year (up from 3.5 per cent in 2014) and remain there over the medium term but, despite the rise, it will continue to be the lowest in Canada.

The slowdown in the economic outlook will also decrease household consumption by 0.8 per cent this year. Retail trade will feel the slight drop in consumption with losses of 3.8 per cent this year. However, in 2016, with the economy picking up again and job growth improving, household consumption and retail trade are both expected to increase by 1.9 per cent.

Forecast Risks

Short term

- Forest fires in the northern areas of the province might result in a further contraction of the economy in 2015.

Medium term

- If COOL legislation is modified into voluntary labelling requirements rather than repealed completely, retaliatory tariffs against the U.S. might be imposed resulting in a damaged relationship between the two countries at the expense of the agriculture sector.

Source: The Conference Board of Canada.

Key Economic Indicators: Saskatchewan

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	85,515	85,852	85,883	86,587	83,397	83,399	84,033	84,746	86,656	87,549	88,390	88,897	85,959	83,894	87,873
	1.8	*0.4*	*0.0*	*0.8*	*-3.7*	*0.0*	*0.8*	*0.8*	*2.3*	*1.0*	*1.0*	*0.6*	*3.3*	*-2.4*	*4.7*
GDP at market prices (2007 $ millions)	63,108	63,531	63,219	64,481	63,485	63,159	63,423	63,766	64,595	64,949	65,353	65,564	63,585	63,458	65,115
	0.1	*0.7*	*-0.5*	*2.0*	*-1.5*	*-0.5*	*0.4*	*0.5*	*1.3*	*0.5*	*0.6*	*0.3*	*1.4*	*-0.2*	*2.6*
GDP at basic prices (2007 $ millions)	59,644	60,045	59,750	60,942	60,001	59,693	59,943	60,266	61,049	61,383	61,764	61,961	60,095	59,976	61,539
	0.1	*0.7*	*-0.5*	*2.0*	*-1.5*	*-0.5*	*0.4*	*0.5*	*1.3*	*0.5*	*0.6*	*0.3*	*1.4*	*-0.2*	*2.6*
Consumer price index (2002 = 1.0)	1.276	1.290	1.291	1.291	1.293	1.306	1.314	1.320	1.327	1.336	1.343	1.347	1.287	1.308	1.338
	1.0	*1.1*	*0.1*	*0.0*	*0.2*	*1.0*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*2.4*	*1.7*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.355	1.351	1.359	1.343	1.314	1.320	1.325	1.329	1.342	1.348	1.353	1.356	1.352	1.322	1.349
	1.6	*-0.3*	*0.5*	*-1.2*	*-2.2*	*0.5*	*0.3*	*0.3*	*0.9*	*0.5*	*0.3*	*0.2*	*1.9*	*-2.2*	*2.1*
Wages and salary per employee ($ 000s)	48.815	49.380	49.319	49.389	50.254	50.298	50.379	50.611	50.887	51.148	51.484	51.800	49.226	50.385	51.330
	1.4	*1.2*	*-0.1*	*0.1*	*1.8*	*0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.7*	*0.6*	*3.3*	*2.4*	*1.9*
Primary household income ($ millions)	41,529	42,345	42,648	42,734	43,309	43,740	43,922	44,213	44,651	45,009	45,435	45,805	42,314	43,796	45,225
	-0.9	*2.0*	*0.7*	*0.2*	*1.3*	*1.0*	*0.4*	*0.7*	*1.0*	*0.8*	*0.9*	*0.8*	*1.7*	*3.5*	*3.3*
Household disposable income ($ millions)	36,599	37,184	37,478	37,467	38,056	38,372	38,758	38,819	39,116	39,444	39,833	40,172	37,182	38,501	39,641
	-0.5	*1.6*	*0.8*	*0.0*	*1.6*	*0.8*	*1.0*	*0.2*	*0.8*	*0.8*	*1.0*	*0.9*	*1.7*	*3.5*	*3.0*
Household net savings rate (per cent)	5.5	6.2	6.2	6.6	8.8	7.7	7.8	7.2	7.1	7.0	7.1	7.1	6.2	7.9	7.1
Population (000s)	1,115	1,120	1,125	1,130	1,133	1,134	1,139	1,143	1,148	1,153	1,158	1,163	1,123	1,137	1,156
	0.3	*0.4*	*0.5*	*0.4*	*0.2*	*0.2*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.7*	*1.3*	*1.6*
Employment (000s)	566	569	573	575	568	576	575	576	577	578	580	580	571	574	579
	0.0	*0.5*	*0.7*	*0.5*	*-1.2*	*1.3*	*0.0*	*0.1*	*0.3*	*0.2*	*0.2*	*0.1*	*1.0*	*0.5*	*0.9*
Labour force (000s)	592	591	594	597	596	604	604	604	605	606	608	609	593	602	607
	0.4	*-0.1*	*0.5*	*0.5*	*-0.2*	*1.3*	*0.0*	*0.1*	*0.2*	*0.2*	*0.3*	*0.1*	*0.7*	*1.4*	*0.9*
Labour force participation rate (per cent)	69.8	69.4	69.6	69.7	69.4	70.2	70.1	69.9	69.8	69.7	69.6	69.5	69.6	69.9	69.6
Unemployment rate (per cent)	4.3	3.7	3.6	3.6	4.6	4.7	4.7	4.7	4.6	4.6	4.7	4.7	3.8	4.7	4.7
Retail sales ($ millions)	19,216	19,186	19,276	18,894	18,380	18,971	19,079	19,219	19,360	19,480	19,633	19,732	19,143	18,912	19,551
	3.9	*-0.2*	*0.5*	*-2.0*	*-2.7*	*3.2*	*0.6*	*0.7*	*0.7*	*0.6*	*0.8*	*0.5*	*4.6*	*-1.2*	*3.4*
Housing starts (units, 000s)	6,995	8,942	9,585	7,506	5,256	5,705	7,283	7,074	6,750	6,642	6,603	6,597	8,257	6,329	6,648
	-14.1	*27.8*	*7.2*	*-21.7*	*-30.0*	*8.5*	*27.7*	*-2.9*	*-4.6*	*-1.6*	*-0.6*	*-0.1*	*-0.4*	*-23.3*	*5.0*
Net interprovincial migration (000s)	3.2	-0.3	-1.5	0.6	-3.7	0.0	-0.2	-0.3	1.0	0.9	0.7	0.5	0.5	-1.0	0.8
Net international migration (000s)	11.5	15.0	12.3	5.6	5.7	4.0	10.6	10.5	10.4	10.3	10.3	10.2	11.1	7.7	10.3

Shaded 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: Saskatchewan cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	89,011	89,730	90,536	91,343	93,041	94,142	95,137	95,778	96,784	97,758	98,557	99,116	90,155	94,525	98,054
	0.1	*0.8*	*0.9*	*0.9*	*1.9*	*1.2*	*1.1*	*0.7*	*1.1*	*1.0*	*0.8*	*0.6*	*2.6*	*4.8*	*3.7*
GDP at market prices (2007 $ millions)	65,639	65,791	66,030	66,292	66,620	66,826	67,031	67,254	67,440	67,665	67,867	68,064	65,938	66,932	67,759
	0.1	*0.2*	*0.4*	*0.4*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.5*	*1.2*
GDP at basic prices (2007 $ millions)	62,030	62,173	62,398	62,644	62,952	63,145	63,339	63,549	63,725	63,939	64,131	64,318	62,311	63,246	64,028
	0.1	*0.2*	*0.4*	*0.4*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.5*	*1.2*
Consumer price index (2002 = 1.0)	1.355	1.365	1.371	1.375	1.383	1.393	1.400	1.404	1.412	1.422	1.429	1.433	1.367	1.395	1.424
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator—GDP at market prices (2007 = 1.0)	1.356	1.364	1.371	1.378	1.397	1.409	1.419	1.424	1.435	1.445	1.452	1.456	1.367	1.412	1.447
	0.0	*0.6*	*0.5*	*0.5*	*1.4*	*0.9*	*0.7*	*0.3*	*0.8*	*0.7*	*0.5*	*0.3*	*1.3*	*3.3*	*2.5*
Wages and salary per employee ($ 000s)	52.097	52.349	52.671	53.004	53.337	53.636	53.971	54.290	54.637	54.977	55.332	55.710	52.530	53.809	55.164
	0.6	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*2.3*	*2.4*	*2.5*
Primary household income ($ millions)	46,125	46,469	46,857	47,250	47,680	48,048	48,445	48,840	49,284	49,695	50,124	50,564	46,675	48,253	49,917
	0.7	*0.7*	*0.8*	*0.8*	*0.9*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*0.9*	*0.9*	*3.2*	*3.4*	*3.4*
Household disposable income ($ millions)	40,544	40,856	41,203	41,550	41,880	42,223	42,584	42,933	43,294	43,672	44,054	44,437	41,038	42,405	43,864
	0.9	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*3.5*	*3.3*	*3.4*
Household net savings rate (per cent)	7.3	7.3	7.3	7.3	7.3	7.3	7.4	7.3	7.4	7.5	7.5	7.6	7.3	7.3	7.5
Population (000s)	1,167	1,172	1,177	1,181	1,186	1,190	1,194	1,198	1,202	1,205	1,209	1,213	1,174	1,192	1,207
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.6*	*1.5*	*1.3*
Employment (000s)	581	581	582	583	583	584	585	585	586	587	588	588	582	584	587
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.5*	*0.5*	*0.5*
Labour force (000s)	609	610	611	611	612	613	614	615	616	617	618	619	610	614	617
	0.1	*0.1*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.1*	*0.2*	*0.5*	*0.5*	*0.6*
Labour force participation rate (per cent)	69.3	69.1	69.0	68.8	68.7	68.6	68.5	68.3	68.3	68.2	68.1	68.0	69.0	68.5	68.1
Unemployment rate (per cent)	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.7	4.8	4.9
Retail sales ($ millions)	19,804	19,872	19,974	20,095	20,211	20,317	20,432	20,546	20,663	20,777	20,905	21,024	19,936	20,376	20,842
	0.4	*0.3*	*0.5*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*2.0*	*2.2*	*2.3*
Housing starts (units, 000s)	6,671	6,795	6,748	6,628	6,242	6,096	6,030	6,024	5,990	5,984	5,948	5,941	6,710	6,098	5,966
	1.1	*1.9*	*−0.7*	*−1.8*	*−5.8*	*−2.3*	*−1.1*	*−0.1*	*−0.6*	*−0.1*	*−0.6*	*−0.1*	*0.9*	*−9.1*	*−2.2*
Net interprovincial migration (000s)	0.6	0.3	−0.1	−0.6	−1.7	−2.1	−2.4	−2.5	−2.2	−2.2	−2.2	−2.2	0.0	−2.2	−2.2
Net international migration (000s)	10.3	10.2	10.1	10.0	9.9	9.7	9.6	9.5	9.4	9.3	9.2	9.1	10.1	9.7	9.3

Shaded 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 Owusu

Alberta's Economy Shifts to Reverse Gear

Highlights

- Lower crude oil prices are moderating the demand for new homes in 2015–16.
- Cuts to capital budgets and the workforce in the energy sector will push up the jobless rate over the next nine months.
- Increased bitumen production will bolster exports and help minimize the impact of lower investment on the economy.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	4.4	−1.0	1.7
Consumer Price Index	2.6	0.9	2.2
Household disposable income	6.3	3.3	2.7
Employment	2.2	1.2	0.3
Unemployment rate (level)	4.7	5.6	5.9
Retail sales	7.5	−2.7	2.6
Wages and salaries per employee	4.5	0.7	2.2
Population	2.9	2.0	1.7

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

Government and Background Information

Premier	Rachel Notley
Next election	Before June 1, 2019
Population (2015Q2)	4,175,409
Government balance (2015–16)	–$5 billion

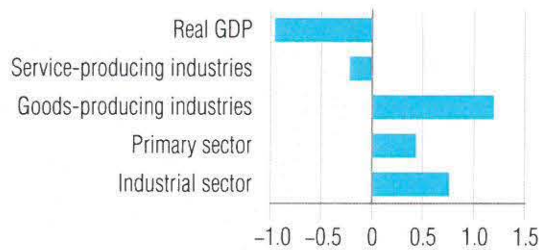
Sources: The Conference Board of Canada; Alberta Budget Documents.

After cruising in fourth speed for the last five years, Alberta's economy shifts to reverse gear this year as the economy faces headwinds stemming from the crude oil price rout. With the downturn in the energy sector, the first half of the year was difficult. The second half of the year is expected to be equally challenging as more layoffs begin to hit home and builders retreat further from breaking ground for new homes. In all, real GDP is forecast to contract by 1.0 per cent this year.

Bearish market conditions for crude stock at the onset of the summer trading season pressured crude oil prices to lose the momentum gathered during the spring. And, with crude prices still off by 50 per cent from their peak in the summer of 2014, several oil firms have slashed their planned investment for this year. The steep reduction in oil-patch investment is evident in the number of oil drilling rigs in operation during the crucial peak winter season. Rig counts in the province were down by 48 per cent during the first half of this year, compared with the same period a year ago. The job losses accompanying the reduction in investment will hurt the housing market, weaken migration trends, and batter the consumer sector. Government revenues from corporate income taxes as well as resource royalties will be under severe pressure this year.

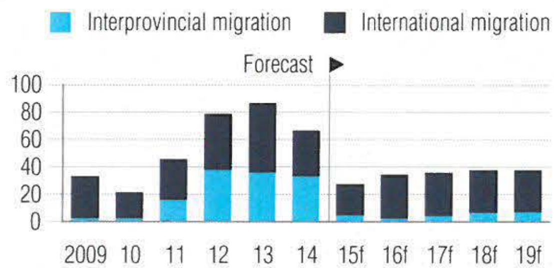
A return to annual economic growth of over 4 per cent is not in the cards for Alberta since crude prices are not likely to return to the triple-digit trading range any time soon. The decline in oil prices is affecting not

Contributions to Alberta Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



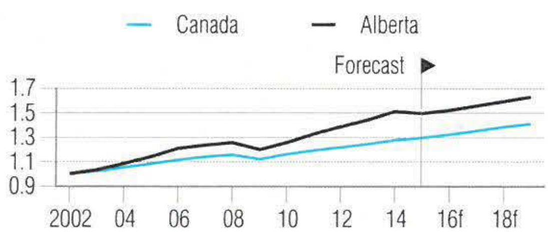
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

only oil-patch businesses and government revenues. Consumers are having a double whammy of weak job prospects and new tax measures. With consumer confidence down, retailers are feeling the downturn.

However, the news is not all bad for Albertans. Heavy investment in recent years has helped to build a lot of capacity in the oil and gas sector, and that is paying dividends in the form of higher oil production. Even though oil prices have dropped, non-conventional oil production continues to flow south to refineries along the U.S. Gulf Coast where demand for heavy oil remains high. And, with import levels falling (due in part to the drop in machinery and equipment purchases associated with oil-patch development), net trade will remain a positive influence on the economy over the short term. Together, a positive net trade balance and more stable economic conditions will help lift real GDP by 1.7 per cent next year.

LOWER OIL PRICE HITS OIL-PATCH INVESTMENT

The drop of more than 50 per cent in crude oil prices is having a predictable impact on Alberta's oil patch. Drilling activities plummeted in the first quarter—considered the peak of the drilling season—as rotary oil rigs were idled. In fact, several oil firms have reduced their investments to align with the weak pricing outlook brought on by the oil glut. Energy investment in nominal terms is expected to fall by 15.8 per cent this year, pulling more than $8 billion out of the economy, and it will not recover before next year. And, even then, recovery will be slow and a return to the level of investment before crude prices collapsed will not occur in the medium term, since crude prices are not likely to return to triple-digit levels any time soon.

The plunge in crude oil prices is hitting not only oil-patch investment but is also putting a severe damper on Alberta's red-hot housing market. The oil patch acted as a magnet to pull in migrants from different parts of the country and from abroad, generating a lot of residential construction activities to accommodate the influx of immigrants. However, with oil firms slamming the brakes on investment and on hiring in response to lower crude oil prices, we project that net annual inflows of immigrants will drop to around 31,000 over the next two years (down from an average of 78,000 for the last three years). Slower immigrant inflows, combined with job losses from the oil rout, will stifle demand for new housing. Housing starts are expected to average around 33,000 units over 2015–16 and, with that, real residential construction investment is anticipated to contract by an average of 7.6 per cent over that period.

DOMESTIC ECONOMY EXPECTED TO REMAIN WEAK

After benefiting from years of wage premiums and hiring blitzes that helped boost household consumption expenditures, Albertans are now taking a break from their prolific spending as the oil rout hits their paycheques.

Oil and gas companies are reducing their capital plans and renegotiating labour and supply contracts. Layoffs have begun and paycheques slashed[1] as lower oil prices hit the bottom lines of energy firms. Our forecast calls for employment to contract in the second half of this year, particularly in the construction and resource sectors as many energy firms have started a second round of capital and labour retrenchment. Job seekers will struggle next year to find employment in these sectors as employers continue to adjust to the impact of lower crude prices. The slowdown in demand for workers, plus the increase in the available labour pool as migrants from other provinces and abroad continue to move to Alberta, will push the unemployment rate up to 5.9 per cent next year, up from 4.4 per cent in November last year when OPEC decided to let the market correct itself.

On the wage front, our forecast calls for only a modest gain of 1.7 per cent for average weekly wages (industrial composite) compared with the average annual gains of 4.4 per cent over the past decade. A new progressive personal income tax rate that is going into effect on October 1 will hit some 7 per cent of tax filers and rake in about $1 billion for government coffers in this fiscal year along with the extra $530 million from the fuel tax increase. The new tax measures along with weaker job prospects and slower net inflow of migrants will put a damper on consumer demand. Retail sales contracted sharply in the first quarter of this year and we expect sales to slide by 2.7 per cent in 2015 with only a modest recovery slated for next year.

The slowdown in consumer spending will take the steam out of inflation in the province. We anticipate that the increase in the overall consumer price index will fall from 2.6 per cent last year to around 1.5 per cent in each of the next two years.

BITUMEN EXPORTS CONTINUE STRONG

One thing that has remained positive as the provincial economy struggles to cope with lower crude oil prices is the exports of bitumen from the massive oil sands deposits. Energy firms continue to add new capacities to their operations. ConocoPhillips Canada began production in June at its Surmont project south of Fort McMurray, adding 118,000 barrels per day to oil sands output. It is the largest steam-assisted gravity drainage (SADG) facility ever built in Canada. Imperial Oil, Husky, China National Offshore Oil Corporation, and several others are also expected to add new capacity to oil sands production this year. Increased production will help minimize the impact of lower investment on Alberta's economy as exports of crude oil continue to flow to the United States. Refineries along the U.S. Gulf Coast, which are configured to process heavy oil, are taking advantage of weak crude oil prices by running at full capacity.

1 Carrie Tait, "Trinidad Drilling Slashes Jobs, Wages Amid Oil Slump," *The Globe and Mail*, February 17, 2015. www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/trinidad-drilling-slashes-jobs-wages-amid-oil-slump/article23035939/.

Our forecast calls for non-conventional oil production to increase by an average of 6.9 per cent in each of the next five years in response to favourable refinery demand conditions south of the border (although that is down from around 10 per cent over 2010–14). At the same time, conventional oil production, which is more price-sensitive than non-conventional oil, will take a much bigger hit from the drop in crude prices and that will result in lower production going forward. All things considered, total crude production is projected to advance over the medium term.

Forecast Risks

Short term

- Oil prices could stay lower for a longer period as oil markets are still oversupplied.

Medium term

- New export capacity for crude oil is still needed, but political wrangling has left the future of this issue cloudy. Without the new capacity, exports of oil could be constrained at the beginning of the next decade.

Source: The Conference Board of Canada.

Key Economic Indicators: Alberta

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	362,853	367,266	367,642	365,787	351,970	350,226	354,174	356,704	363,637	367,928	372,607	376,639	365,887	353,268	370,203
	4.5	*1.2*	*0.1*	*-0.5*	*-3.8*	*-0.5*	*1.1*	*0.7*	*1.9*	*1.2*	*1.3*	*1.1*	*8.2*	*-3.4*	*4.8*
GDP at market prices (2007 $ millions)	311,678	316,422	316,362	320,970	314,402	311,226	313,408	314,167	316,143	317,501	319,518	321,139	316,358	313,301	318,575
	0.8	*1.5*	*0.0*	*1.5*	*-2.0*	*-1.0*	*0.7*	*0.2*	*0.6*	*0.4*	*0.6*	*0.5*	*4.4*	*-1.0*	*1.7*
GDP at basic prices (2007 $ millions)	301,003	305,585	305,527	309,977	303,634	300,567	302,674	303,407	305,315	306,627	308,575	310,140	305,523	302,570	307,664
	0.8	*1.5*	*0.0*	*1.5*	*-2.0*	*-1.0*	*0.7*	*0.2*	*0.6*	*0.4*	*0.6*	*0.5*	*4.4*	*-1.0*	*1.7*
Consumer price index (2002 = 1.0)	1.313	1.324	1.328	1.323	1.320	1.331	1.340	1.345	1.351	1.361	1.368	1.372	1.322	1.334	1.363
	1.5	*0.9*	*0.3*	*-0.4*	*-0.2*	*0.9*	*0.6*	*0.4*	*0.5*	*0.7*	*0.5*	*0.3*	*2.6*	*0.9*	*2.2*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.164	1.161	1.162	1.140	1.119	1.125	1.130	1.135	1.150	1.159	1.166	1.173	1.157	1.128	1.162
	3.7	*-0.3*	*0.1*	*-1.9*	*-1.8*	*0.5*	*0.4*	*0.5*	*1.3*	*0.7*	*0.6*	*0.6*	*3.6*	*-2.5*	*3.1*
Wages and salary per employee ($ 000s)	66.176	66.813	67.804	67.755	67.390	67.492	67.532	67.943	68.281	68.821	69.362	69.870	67.137	67.589	69.084
	0.4	*1.0*	*1.5*	*-0.1*	*-0.5*	*0.2*	*0.1*	*0.6*	*0.5*	*0.8*	*0.8*	*0.7*	*4.5*	*0.7*	*2.2*
Primary household income ($ millions)	200,885	204,163	207,454	209,772	210,737	211,828	211,883	212,511	214,490	216,931	219,537	222,118	205,568	211,740	218,269
	1.3	*1.6*	*1.6*	*1.1*	*0.5*	*0.5*	*0.0*	*0.3*	*0.9*	*1.1*	*1.2*	*1.2*	*6.6*	*3.0*	*3.1*
Household disposable income ($ millions)	168,373	170,335	173,103	174,678	176,635	177,226	177,707	177,718	179,036	181,050	183,200	185,280	171,622	177,321	182,142
	1.1	*1.2*	*1.6*	*0.9*	*1.1*	*0.3*	*0.3*	*0.0*	*0.7*	*1.1*	*1.2*	*1.1*	*6.3*	*3.3*	*2.7*
Household net savings rate (per cent)	15.8	15.8	16.0	16.4	18.4	18.0	18.1	17.6	17.4	17.4	17.4	17.4	16.0	18.0	17.4
Population (000s)	4,060	4,087	4,122	4,146	4,160	4,175	4,193	4,211	4,228	4,246	4,265	4,283	4,104	4,185	4,255
	0.5	*0.7*	*0.9*	*0.6*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.9*	*2.0*	*1.7*
Employment (000s)	2,256	2,270	2,274	2,294	2,305	2,308	2,301	2,290	2,297	2,304	2,313	2,322	2,274	2,301	2,309
	0.7	*0.6*	*0.2*	*0.9*	*0.5*	*0.1*	*-0.3*	*-0.5*	*0.3*	*0.3*	*0.4*	*0.4*	*2.2*	*1.2*	*0.3*
Labour force (000s)	2,367	2,386	2,388	2,402	2,429	2,446	2,440	2,436	2,443	2,449	2,457	2,462	2,386	2,438	2,453
	0.7	*0.8*	*0.1*	*0.6*	*1.1*	*0.7*	*-0.3*	*-0.1*	*0.3*	*0.2*	*0.3*	*0.2*	*2.3*	*2.2*	*0.6*
Labour force participation rate (per cent)	72.9	72.9	72.5	72.5	73.0	73.2	72.7	72.4	72.3	72.2	72.2	72.0	72.7	72.8	72.2
Unemployment rate (per cent)	4.7	4.9	4.8	4.5	5.1	5.6	5.7	6.0	6.0	5.9	5.9	5.7	4.7	5.6	5.9
Retail sales ($ millions)	77,699	78,100	79,625	78,904	76,029	76,638	76,347	76,745	77,272	78,012	78,813	79,493	78,582	76,440	78,397
	4.0	*0.5*	*2.0*	*-0.9*	*-3.6*	*0.8*	*-0.4*	*0.5*	*0.7*	*1.0*	*1.0*	*0.9*	*7.5*	*-2.7*	*2.6*
Housing starts (units, 000s)	37,830	42,585	42,999	38,945	45,306	35,784	30,928	28,665	28,682	29,594	30,507	31,419	40,590	35,171	30,050
	-3.8	*12.6*	*1.0*	*-9.4*	*16.3*	*-21.0*	*-13.6*	*-7.3*	*0.1*	*3.2*	*3.1*	*3.0*	*12.7*	*-13.4*	*-14.6*
Net interprovincial migration (000s)	38.3	52.8	25.3	16.7	26.9	-5.1	-1.5	-1.0	1.1	2.5	2.7	3.0	33.3	4.8	2.3
Net international migration (000s)	39.0	50.2	35.4	9.4	4.0	19.6	33.5	33.1	32.5	32.2	31.9	31.8	33.5	22.5	32.1

Shaded 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: Alberta cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	383,168	388,081	392,704	396,653	401,094	405,682	410,164	413,382	418,405	423,369	427,896	431,546	390,151	407,581	425,304
	1.7	*1.3*	*1.2*	*1.0*	*1.1*	*1.1*	*1.1*	*0.8*	*1.2*	*1.2*	*1.1*	*0.9*	*5.4*	*4.5*	*4.3*
GDP at market prices (2007 $ millions)	324,039	325,700	327,715	329,767	331,419	333,028	334,792	336,724	338,519	340,435	342,355	344,242	326,805	333,991	341,388
	0.9	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*2.6*	*2.2*	*2.2*
GDP at basic prices (2007 $ millions)	312,941	314,545	316,490	318,473	320,068	321,622	323,325	325,191	326,925	328,775	330,630	332,452	315,612	322,552	329,695
	0.9	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*2.6*	*2.2*	*2.2*
Consumer price index (2002 = 1.0)	1.380	1.390	1.397	1.401	1.409	1.419	1.426	1.430	1.438	1.448	1.456	1.460	1.392	1.421	1.451
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.182	1.192	1.198	1.203	1.210	1.218	1.225	1.228	1.236	1.244	1.250	1.254	1.194	1.220	1.246
	0.8	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.6*	*0.2*	*0.7*	*0.6*	*0.5*	*0.3*	*2.7*	*2.2*	*2.1*
Wages and salary per employee ($ 000s)	70.342	70.762	71.215	71.689	72.155	72.649	73.170	73.683	74.179	74.751	75.338	75.952	71.002	72.914	75.055
	0.7	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.8*	*0.8*	*0.8*	*2.8*	*2.7*	*2.9*
Primary household income ($ millions)	224,473	226,924	229,395	231,886	234,280	236,469	239,035	241,552	244,335	247,314	250,326	253,385	228,170	237,834	248,840
	1.1	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*	*1.2*	*4.5*	*4.2*	*4.6*
Household disposable income ($ millions)	187,469	189,413	191,353	193,333	195,167	196,990	199,095	201,145	203,372	205,809	208,266	210,723	190,392	198,099	207,042
	1.2	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*1.1*	*1.0*	*1.1*	*1.2*	*1.2*	*1.2*	*4.5*	*4.0*	*4.5*
Household net savings rate (per cent)	17.6	17.6	17.6	17.6	17.6	17.6	17.7	17.6	17.7	17.7	17.8	17.9	17.6	17.6	17.8
Population (000s)	4,302	4,321	4,340	4,359	4,377	4,396	4,415	4,435	4,454	4,473	4,493	4,512	4,331	4,406	4,483
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.8*	*1.7*	*1.7*
Employment (000s)	2,331	2,340	2,349	2,357	2,363	2,367	2,375	2,381	2,389	2,398	2,407	2,416	2,345	2,371	2,403
	0.4	*0.4*	*0.4*	*0.4*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*1.6*	*1.1*	*1.3*
Labour force (000s)	2,468	2,473	2,477	2,483	2,487	2,492	2,498	2,505	2,514	2,522	2,532	2,540	2,476	2,495	2,527
	0.3	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.9*	*0.8*	*1.3*
Labour force participation rate (per cent)	71.9	71.8	71.7	71.6	71.4	71.3	71.2	71.1	71.0	71.0	71.0	71.0	71.7	71.2	71.0
Unemployment rate (per cent)	5.5	5.4	5.2	5.1	5.0	5.0	4.9	5.0	5.0	4.9	4.9	4.9	5.3	5.0	4.9
Retail sales ($ millions)	80,040	80,590	81,190	81,897	82,548	83,110	83,809	84,499	85,245	86,051	86,908	87,721	80,929	83,492	86,481
	0.7	*0.7*	*0.7*	*0.9*	*0.8*	*0.7*	*0.8*	*0.8*	*0.9*	*0.9*	*1.0*	*0.9*	*3.2*	*3.2*	*3.6*
Housing starts (units, 000s)	28,806	29,722	30,635	31,551	29,390	30,308	31,223	32,141	33,088	33,165	33,237	33,310	30,179	30,766	33,200
	–8.3	*3.2*	*3.1*	*3.0*	*–6.8*	*3.1*	*3.0*	*2.9*	*2.9*	*0.2*	*0.2*	*0.2*	*0.4*	*1.9*	*7.9*
Net interprovincial migration (000s)	3.7	4.1	4.1	4.5	5.5	6.5	6.7	7.0	7.1	7.2	7.3	7.4	4.1	6.4	7.3
Net international migration (000s)	31.8	31.7	31.5	31.4	31.3	31.2	31.1	30.9	30.7	30.6	30.5	30.3	31.6	31.1	30.5

Shaded 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.

Elise Martin

British Columbia Will Lead the Provinces This Year and Next

Highlights

- British Columbia's economy will grow by 2.8 per cent in 2015, the fastest pace of all the provinces.
- The residential housing market is still hot, with 31,580 units breaking ground this year.
- Metal mining will be a drag on the overall bottom line this year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	2.6	2.8	3.4
Consumer Price Index	1.0	1.3	2.3
Household disposable income	3.4	3.6	4.1
Employment	0.6	0.7	1.6
Unemployment rate (level)	6.1	6.0	5.9
Retail sales	5.6	7.3	4.7
Wages and salaries per employee	3.1	2.4	2.4
Population	1.1	1.0	1.2

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

Government and Background Information

Premier	Christy Clark
Next election	May 2017
Population (2015Q2)	4,666,892
Government balance (2015–16)	$284 million

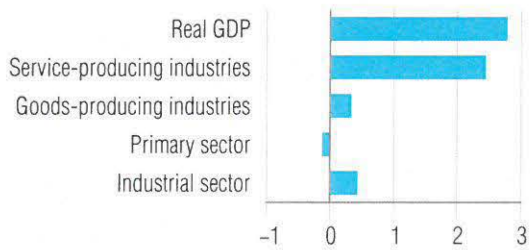
Sources: The Conference Board of Canada; B.C. Finance.

British Columbia's economy is firing on all cylinders. Provincial real GDP will grow at the fastest rate of all 10 provinces in both 2015 and 2016. The economy will advance by 2.8 per cent in 2015 and 3.5 per cent in 2016.

This year, the province will benefit from strong growth in manufacturing and healthy gains in the services sector. Year-to-date (ending in June) exports of manufacturing goods have been on the rise, especially in the metal products manufacturing and transportation equipment manufacturing. Stronger economic growth in the U.S. will continue to support gains in the export categories. Construction will be a drag on the provincial bottom line this year as several projects were completed but next year will bring a substantial rebound as several new projects get under way. Metal mining is also forecast to decline in 2015 as a result of the shutdown of both the Endako and Mount Polley mines. However, metal mining will turn around next year as production ramps up at the Mount Milligan and the Red Chris gold-copper mines.

On the energy front, the province passed legislation on July 21st, to enter into an agreement with Pacific NorthWest LNG, a consortium led by Malaysian energy giant Petronas, to build an LNG export terminal near Prince Rupert. The two remaining barriers to this $36-billion project include First Nation's rights and the

Contributions to British Columbia Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)

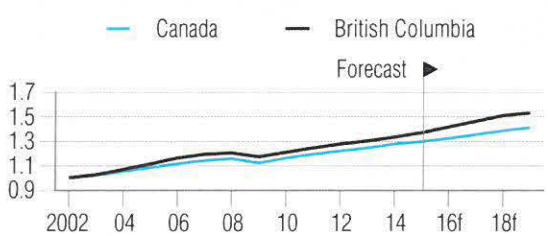


Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)

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

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



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

environmental assessment approval. If it goes ahead, it would be the largest private sector investment in the province's history.

EXPORTS GAINS LIFTS THE PROVINCE TO NUMBER ONE IN GDP GROWTH

Over the first five months of 2015, British Columbia saw gains across a wide range of export categories, including aircraft products and services, motor vehicles, and machinery and equipment. Provincial exports are expected to do well as the United States, B.C.'s main trading partner, is gaining economic momentum.

Total housing starts in the U.S. will grow by an average of 25.7 per cent per year over the next two years. However, despite rising demand by the new housing sector in the U.S., growth in the province's forestry industry will dip this year. Because of the mountain pine beetle infestation, a much more limited timber supply is available as many of the hardest-hit areas have already been harvested. As a result, output in the forestry sector will decline by 2.4 per cent in 2015 and 1.5 per cent next year.

After remarkable 29.1 per cent growth last year, metal mining will be a drag on the economy in 2015 as production is expected to decline. The slump comes partly as a result of Thompson Creek's shutting down its Endako mine due to low molybdenum prices. The shutdown was originally announced as temporary in December 2014; however, the mine was put on a care and maintenance footing on July 1. In addition, the shutdown of the Mount Polley mine due to the tailing pond collapse in August 2014 will continue to weigh on the province's metal mining production. The B.C. government has now given the go-ahead for the Mount Polley mine to restart at half capacity and activities could resume as soon as mid-August. Overall, total mining will fall by 1.9 per cent in 2015 but is forecast to rebound in 2016 by 3 per cent.

MANUFACTURING TO DO WELL

Manufacturing is expected to provide a solid base for the provincial economy over the next few years. B.C.'s shipbuilding industry, which has struggled to survive for decades, has had new life breathed into it by the federal government. At the end of June, Seaspan Shipyards started working on an enormous $8-billion federal shipbuilding contract for the construction of non-combat vessels for the Canadian Coast Guard and the Royal Canadian Navy. All told, manufacturing will advance by 8.8 per cent this year and 3.7 per cent in 2016.

CONSTRUCTION WILL DECLINE THIS YEAR BUT PICK UP AGAIN IN 2016

Construction growth will fall into negative territory in 2015 after expanding by 3.1 per cent in 2014, the decrease coming from a slump in non-residential construction. Two large mining projects (Mount Milligan and Red Chris), which boosted construction output over the past several years, have been moved into production. However, the construction decline will not last long; other projects are set to get under way shortly, including the expansion of the Prince Rupert port and construction of a number of energy projects. This investment will spur a 21.4 per cent rebound in the non-residential construction sector in 2016.

No liquid natural gas (LNG) terminals are yet under construction, but work on the Pacific NorthWest LNG, LNG Canada, Kitimat LNG, and Douglas Channel LNG terminals could start before the end of 2018. No fewer than 19 LNG project proposals are on the table in British Columbia. However, only a handful of terminals are likely to take advantage of the window of opportunity before the gap closes between the price of natural gas in North America and Asia. The Malaysian energy producer Petronas is expected to put shovels in the ground as soon as the federal government issues a positive regulatory decision on the project's environmental assessment. The Lax Kw'alaams, an Indigenous band in northern British Columbia, is spearheading the opposition movement to the Pacific NorthWest LNG terminal near Prince Rupert. They turned down a $1.15-billion deal with Petronas over concerns that the LNG terminal will harm an essential juvenile salmon habitat.

Residential construction will post strong growth this year as housing starts are projected to continue increasing, defying the national trend. But, all told, construction will decrease by 3.1 per cent in 2015 and then jump up by 10.9 per cent in 2016.

DOMESTIC DEMAND

Labour markets will continue to increase slightly in British Columbia. Strong growth in manufacturing, as well as a respectable performance by the services industry, will help support labour market growth in the near term. The unemployment rate will continue to edge down to 5.9 per cent by the end of 2016, well below the national average of 6.9 per cent. Healthy advances in wages and salaries will provide support for consumer spending. High prices, historically low interest rates, and steady demand for housing will be behind the elevated levels of buying and selling activity this year, lifting the financial services sector. All told, the services sector will expand by 3.3 per cent in 2015 and 2.8 per cent in 2016.

Forecast Risks

Short term

- Prolonged or permanent mine shutdowns could lower mining output.

Medium term

- A subdued Chinese economy could cool offshore demand for Vancouver real estate.

Source: The Conference Board of Canada.

Key Economic Indicators: British Columbia

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	235,592	238,644	241,326	245,895	245,561	249,826	253,735	256,760	258,684	261,957	265,887	269,127	240,364	251,471	263,914
	0.5	*1.3*	*1.1*	*1.9*	*-0.1*	*1.7*	*1.6*	*1.2*	*0.7*	*1.3*	*1.5*	*1.2*	*4.6*	*4.6*	*4.9*
GDP at market prices (2007 $ millions)	217,494	219,609	221,287	224,437	224,648	225,808	227,625	229,343	231,665	233,519	235,937	237,610	220,707	226,856	234,683
	-0.7	*1.0*	*0.8*	*1.4*	*0.1*	*0.5*	*0.8*	*0.8*	*1.0*	*0.8*	*1.0*	*0.7*	*2.6*	*2.8*	*3.5*
GDP at basic prices (2007 $ millions)	200,374	202,323	203,869	206,771	206,968	208,036	209,709	211,290	213,427	215,131	217,355	218,891	203,335	209,001	216,201
	-0.7	*1.0*	*0.8*	*1.4*	*0.1*	*0.5*	*0.8*	*0.8*	*1.0*	*0.8*	*1.0*	*0.7*	*2.6*	*2.8*	*3.4*
Consumer price index (2002 = 1.0)	1.179	1.195	1.196	1.186	1.189	1.204	1.211	1.216	1.223	1.231	1.237	1.241	1.189	1.205	1.233
	0.5	*1.4*	*0.1*	*-0.8*	*0.2*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.0*	*1.3*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.083	1.087	1.091	1.096	1.093	1.106	1.115	1.120	1.117	1.122	1.127	1.133	1.089	1.108	1.124
	1.2	*0.3*	*0.4*	*0.5*	*-0.2*	*1.2*	*0.8*	*0.4*	*-0.3*	*0.5*	*0.5*	*0.5*	*2.0*	*1.8*	*1.4*
Wages and salary per employee ($ 000s)	45.061	44.742	45.140	45.573	45.877	46.083	46.371	46.593	46.865	47.165	47.514	47.887	45.129	46.231	47.358
	1.0	*-0.7*	*0.9*	*1.0*	*0.7*	*0.4*	*0.6*	*0.5*	*0.6*	*0.6*	*0.7*	*0.8*	*3.1*	*2.4*	*2.4*
Primary household income ($ millions)	169,170	168,741	169,729	172,218	174,525	174,877	176,837	178,587	180,583	182,665	184,911	187,266	169,964	176,206	183,856
	1.6	*-0.3*	*0.6*	*1.5*	*1.3*	*0.2*	*1.1*	*1.0*	*1.1*	*1.2*	*1.2*	*1.3*	*4.0*	*3.7*	*4.3*
Household disposable income ($ millions)	149,769	148,945	149,772	151,602	153,849	154,013	156,450	157,250	158,923	160,730	162,697	164,744	150,022	155,390	161,774
	1.3	*-0.6*	*0.6*	*1.2*	*1.5*	*0.1*	*1.6*	*0.5*	*1.1*	*1.1*	*1.2*	*1.3*	*3.4*	*3.6*	*4.1*
Household net savings rate (per cent)	1.1	-1.5	-2.0	-2.1	-1.8	-3.0	-2.9	-3.5	-3.7	-3.7	-3.7	-3.6	-1.1	-2.8	-3.7
Population (000s)	4,605	4,617	4,631	4,658	4,659	4,667	4,680	4,694	4,708	4,722	4,737	4,751	4,628	4,675	4,730
	0.0	*0.3*	*0.3*	*0.6*	*0.0*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.0*	*1.2*
Employment (000s)	2,277	2,280	2,274	2,282	2,288	2,286	2,295	2,303	2,313	2,325	2,336	2,348	2,278	2,293	2,331
	0.6	*0.1*	*-0.3*	*0.4*	*0.3*	*-0.1*	*0.4*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.6*	*0.7*	*1.6*
Labour force (000s)	2,429	2,428	2,424	2,422	2,429	2,434	2,443	2,452	2,460	2,470	2,482	2,493	2,426	2,439	2,476
	0.2	*-0.1*	*-0.2*	*-0.1*	*0.3*	*0.2*	*0.4*	*0.4*	*0.3*	*0.4*	*0.5*	*0.4*	*0.0*	*0.6*	*1.5*
Labour force participation rate (per cent)	63.7	63.5	63.2	63.0	63.0	62.9	63.0	63.0	63.1	63.1	63.2	63.3	63.3	63.0	63.2
Unemployment rate (per cent)	6.3	6.1	6.2	5.8	5.8	6.1	6.1	6.1	6.0	5.9	5.9	5.8	6.1	6.0	5.9
Retail sales ($ millions)	64,056	66,033	67,124	67,880	69,223	70,840	71,728	72,562	73,352	74,065	74,848	75,586	66,273	71,088	74,463
	0.2	*3.1*	*1.7*	*1.1*	*2.0*	*2.3*	*1.3*	*1.2*	*1.1*	*1.0*	*1.1*	*1.0*	*5.6*	*7.3*	*4.7*
Housing starts (units, 000s)	27,199	27,640	29,403	29,182	30,128	33,129	31,726	31,339	31,200	31,259	31,570	31,993	28,356	31,580	31,505
	-8.3	*1.6*	*6.4*	*-0.7*	*3.2*	*10.0*	*-4.2*	*-1.2*	*-0.4*	*0.2*	*1.0*	*1.3*	*4.8*	*11.4*	*-0.2*
Net interprovincial migration (000s)	5.2	7.9	16.9	10.2	15.2	9.5	8.8	9.2	10.4	10.6	11.0	11.2	10.0	10.7	10.8
Net international migration (000s)	34.8	38.4	75.0	-12.6	9.3	35.3	39.0	39.7	40.5	41.2	41.8	42.3	33.9	30.8	41.4

Shaded 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: British Columbia cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	274,666	278,708	282,474	285,877	290,614	294,255	297,448	299,273	302,130	304,645	306,467	307,332	280,431	295,398	305,144
	2.1	*1.5*	*1.4*	*1.2*	*1.7*	*1.3*	*1.1*	*0.6*	*1.0*	*0.8*	*0.6*	*0.3*	*6.3*	*5.3*	*3.3*
GDP at market prices (2007 $ millions)	239,705	241,340	243,214	245,258	248,002	249,548	250,887	251,964	252,706	253,290	253,566	253,548	242,379	250,100	253,277
	0.9	*0.7*	*0.8*	*0.8*	*1.1*	*0.6*	*0.5*	*0.4*	*0.3*	*0.2*	*0.1*	*0.0*	*3.3*	*3.2*	*1.3*
GDP at basic prices (2007 $ millions)	220,815	222,315	224,036	225,912	228,426	229,846	231,077	232,071	232,757	233,302	233,565	233,559	223,270	230,355	233,296
	0.9	*0.7*	*0.8*	*0.8*	*1.1*	*0.6*	*0.5*	*0.4*	*0.3*	*0.2*	*0.1*	*0.0*	*3.3*	*3.2*	*1.3*
Consumer price index (2002 = 1.0)	1.249	1.257	1.263	1.267	1.275	1.283	1.290	1.293	1.301	1.310	1.316	1.321	1.259	1.285	1.312
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.146	1.155	1.161	1.166	1.172	1.179	1.186	1.188	1.196	1.203	1.209	1.212	1.157	1.181	1.205
	1.2	*0.8*	*0.6*	*0.4*	*0.5*	*0.6*	*0.5*	*0.2*	*0.7*	*0.6*	*0.5*	*0.3*	*2.9*	*2.1*	*2.0*
Wages and salary per employee ($ 000s)	48	49	49	49	50	50	51	51	51	52	52	52	49	50	52
	0.7	*0.6*	*0.8*	*0.8*	*0.9*	*0.8*	*0.8*	*0.8*	*0.7*	*0.5*	*0.7*	*0.7*	*2.9*	*3.3*	*2.8*
Primary household income ($ millions)	189,571	191,802	194,330	196,927	199,705	202,443	205,169	207,543	209,725	211,552	213,530	215,517	193,157	203,715	212,581
	1.2	*1.2*	*1.3*	*1.3*	*1.4*	*1.4*	*1.3*	*1.2*	*1.1*	*0.9*	*0.9*	*0.9*	*5.1*	*5.5*	*4.4*
Household disposable income ($ millions)	167,074	168,976	171,086	173,226	175,332	177,739	180,111	182,143	183,946	185,595	187,338	189,068	170,091	178,831	186,487
	1.4	*1.1*	*1.2*	*1.3*	*1.2*	*1.4*	*1.3*	*1.1*	*1.0*	*0.9*	*0.9*	*0.9*	*5.1*	*5.1*	*4.3*
Household net savings rate (per cent)	−3.4	−3.4	−3.4	−3.4	−3.4	−3.4	−3.3	−3.3	−3.2	−3.1	−3.1	−2.9	−3.4	−3.3	−3.1
Population (000s)	4,767	4,782	4,797	4,813	4,828	4,844	4,860	4,876	4,892	4,908	4,924	4,940	4,790	4,852	4,916
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.3*	*1.3*
Employment (000s)	2,360	2,372	2,384	2,395	2,408	2,420	2,432	2,440	2,445	2,449	2,453	2,457	2,378	2,425	2,451
	0.5	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*2.0*	*2.0*	*1.1*
Labour force (000s)	2,502	2,512	2,520	2,526	2,533	2,547	2,559	2,565	2,571	2,577	2,581	2,586	2,515	2,551	2,579
	0.4	*0.4*	*0.3*	*0.3*	*0.3*	*0.5*	*0.5*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.6*	*1.4*	*1.1*
Labour force participation rate (per cent)	63.3	63.4	63.4	63.3	63.3	63.4	63.5	63.5	63.4	63.4	63.3	63.2	63.4	63.4	63.3
Unemployment rate (per cent)	5.7	5.6	5.4	5.2	4.9	5.0	4.9	4.9	4.9	4.9	5.0	5.0	5.5	4.9	4.9
Retail sales ($ millions)	76,294	76,873	77,615	78,460	79,306	80,240	81,140	81,857	82,404	82,820	83,335	83,807	77,310	80,636	83,092
	0.9	*0.8*	*1.0*	*1.1*	*1.1*	*1.2*	*1.1*	*0.9*	*0.7*	*0.5*	*0.6*	*0.6*	*3.8*	*4.3*	*3.0*
Housing starts (units, 000s)	31,738	31,899	32,246	32,703	32,486	32,266	32,332	31,739	32,197	32,335	32,464	32,797	32,147	32,206	32,448
	−0.8	*0.5*	*1.1*	*1.4*	*−0.7*	*−0.7*	*0.2*	*−1.8*	*1.4*	*0.4*	*0.4*	*1.0*	*2.0*	*0.2*	*0.8*
Net interprovincial migration (000s)	10.8	10.9	11.2	11.3	11.7	11.7	11.7	11.5	11.2	10.9	10.6	10.2	11.0	11.6	10.7
Net international migration (000s)	42.5	43.0	43.4	43.9	44.6	44.9	45.1	45.1	44.8	44.7	44.6	44.6	43.2	44.9	44.7

Shaded 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: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	1,949,952	1,968,220	1,989,532	1,991,596	1,977,028	1,991,904	2,020,504	2,039,621	2,060,259	2,082,485	2,105,580	2,122,723	1,974,825	2,007,264	2,092,762
	1.6	*0.9*	*1.1*	*0.1*	*-0.7*	*0.8*	*1.4*	*0.9*	*1.0*	*1.1*	*1.1*	*0.8*	*4.3*	*1.6*	*4.3*
GDP at market prices (2007 $ millions)	1,726,814	1,741,505	1,755,344	1,765,019	1,762,406	1,767,769	1,780,262	1,788,118	1,796,986	1,806,431	1,819,117	1,826,662	1,747,171	1,774,639	1,812,299
	0.3	*0.9*	*0.8*	*0.6*	*-0.1*	*0.3*	*0.7*	*0.4*	*0.5*	*0.5*	*0.7*	*0.4*	*2.4*	*1.6*	*2.1*
GDP at basic prices (2007 $ millions)	1,619,106	1,633,316	1,644,035	1,653,314	1,650,171	1,655,792	1,667,490	1,674,845	1,683,149	1,691,993	1,703,871	1,710,934	1,637,443	1,662,075	1,697,487
	0.3	*0.9*	*0.7*	*0.6*	*-0.2*	*0.3*	*0.7*	*0.4*	*0.5*	*0.5*	*0.7*	*0.4*	*2.4*	*1.5*	*2.1*
Consumer price index (2002 = 1.0)	1.240	1.256	1.257	1.253	1.253	1.269	1.277	1.282	1.289	1.298	1.304	1.309	1.252	1.270	1.300
	0.9	*1.3*	*0.1*	*-0.4*	*0.1*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.9*	*1.5*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.129	1.130	1.133	1.128	1.122	1.127	1.135	1.141	1.147	1.153	1.157	1.162	1.130	1.131	1.155
	1.4	*0.1*	*0.3*	*-0.4*	*-0.6*	*0.4*	*0.7*	*0.5*	*0.5*	*0.6*	*0.4*	*0.4*	*1.8*	*0.1*	*2.1*
Wages and salary per employee ($ 000s)	47.675	48.103	48.503	48.525	48.853	49.015	49.167	49.417	49.671	49.957	50.260	50.566	48.202	49.113	50.114
	0.7	*0.9*	*0.8*	*0.0*	*0.7*	*0.3*	*0.3*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*2.9*	*1.9*	*2.0*
Primary household income ($ millions)	1,267,068	1,277,288	1,288,484	1,297,264	1,313,792	1,319,631	1,328,981	1,338,651	1,351,524	1,364,221	1,377,267	1,390,433	1,282,526	1,325,264	1,370,861
	1.1	*0.8*	*0.9*	*0.7*	*1.3*	*0.4*	*0.7*	*0.7*	*1.0*	*0.9*	*1.0*	*1.0*	*3.7*	*3.3*	*3.4*
Household disposable income ($ millions)	1,106,124	1,112,676	1,122,860	1,129,208	1,146,308	1,149,608	1,163,890	1,166,535	1,175,775	1,186,630	1,197,542	1,208,477	1,117,717	1,156,585	1,192,106
	1.0	*0.6*	*0.9*	*0.6*	*1.5*	*0.3*	*1.2*	*0.2*	*0.8*	*0.9*	*0.9*	*0.9*	*3.4*	*3.5*	*3.1*
Household net savings rate (per cent)	4.8	3.8	3.7	3.6	5.0	4.0	4.1	3.5	3.3	3.3	3.3	3.4	4.0	4.1	3.3
Population (000s)	35,335	35,416	35,540	35,676	35,703	35,800	35,899	35,999	36,101	36,202	36,304	36,406	35,492	35,850	36,253
	0.1	*0.2*	*0.4*	*0.4*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.0*	*1.1*
Employment (000s)	17,764	17,763	17,794	17,864	17,896	17,928	17,973	17,992	18,049	18,110	18,170	18,229	17,796	17,947	18,139
	0.2	*0.0*	*0.2*	*0.4*	*0.2*	*0.2*	*0.3*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*0.6*	*0.8*	*1.1*
Labour force (000s)	19,104	19,098	19,131	19,139	19,190	19,264	19,302	19,354	19,406	19,461	19,516	19,568	19,118	19,278	19,488
	0.1	*0.0*	*0.2*	*0.0*	*0.3*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.8*	*1.1*
Labour force participation rate (per cent)	66.2	66.0	65.9	65.8	65.8	65.9	65.9	65.9	65.9	65.9	65.9	65.9	66.0	65.9	65.9
Unemployment rate (per cent)	7.0	7.0	7.0	6.7	6.7	6.9	6.9	7.0	7.0	6.9	6.9	6.8	6.9	6.9	6.9
Retail sales ($ millions)	493,515	504,790	511,211	510,514	504,723	515,508	520,185	524,953	529,458	533,804	538,081	541,797	505,008	516,342	535,785
	0.9	*2.3*	*1.3*	*-0.1*	*-1.1*	*2.1*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*	*4.6*	*2.2*	*3.8*
Housing starts (units)	175,834	197,210	196,190	188,082	176,554	189,782	182,520	179,547	176,546	177,261	178,023	179,451	189,329	182,101	177,820
	-11.1	*12.2*	*-0.5*	*-4.1*	*-6.1*	*7.5*	*-3.8*	*-1.6*	*-1.7*	*0.4*	*0.4*	*0.8*	*0.7*	*-3.8*	*-2.4*

Shaded 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 cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	2,150,037	2,173,774	2,196,623	2,216,531	2,244,696	2,269,125	2,292,277	2,307,898	2,333,297	2,357,681	2,379,208	2,395,531	2,184,241	2,278,499	2,366,429
	1.3	*1.1*	*1.1*	*0.9*	*1.3*	*1.1*	*1.0*	*0.7*	*1.1*	*1.0*	*0.9*	*0.7*	*4.4*	*4.3*	*3.9*
GDP at market prices (2007 $ millions)	1,838,736	1,846,891	1,857,580	1,868,930	1,880,596	1,889,666	1,899,080	1,909,152	1,918,032	1,927,301	1,936,360	1,945,035	1,853,034	1,894,624	1,931,682
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*2.2*	*2.2*	*2.0*
GDP at basic prices (2007 $ millions)	1,722,239	1,729,876	1,739,884	1,750,512	1,761,434	1,769,926	1,778,740	1,788,172	1,796,486	1,805,165	1,813,647	1,821,770	1,735,628	1,774,568	1,809,267
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*2.2*	*2.2*	*2.0*
Consumer price index (2002 = 1.0)	1.316	1.325	1.332	1.336	1.344	1.353	1.360	1.363	1.371	1.381	1.388	1.392	1.327	1.355	1.383
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.169	1.177	1.183	1.186	1.194	1.201	1.207	1.209	1.217	1.223	1.229	1.232	1.179	1.203	1.225
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.6*	*0.5*	*0.2*	*0.6*	*0.6*	*0.4*	*0.2*	*2.1*	*2.0*	*1.9*
Wages and salary per employee ($ 000s)	50.886	51.209	51.538	51.863	52.188	52.531	52.875	53.227	53.586	53.950	54.319	54.695	51.374	52.705	54.137
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*2.5*	*2.6*	*2.7*
Primary household income ($ millions)	1,402,824	1,417,249	1,431,521	1,445,577	1,460,473	1,474,581	1,488,917	1,503,413	1,518,965	1,533,560	1,548,324	1,563,215	1,424,293	1,481,846	1,541,016
	0.9	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*3.9*	*4.0*	*4.0*
Household disposable income ($ millions)	1,220,718	1,232,293	1,243,658	1,254,803	1,265,771	1,277,658	1,289,728	1,301,729	1,314,054	1,326,837	1,339,579	1,352,262	1,237,868	1,283,722	1,333,183
	1.0	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*	*0.9*	*3.8*	*3.7*	*3.9*
Household net savings rate (per cent)	3.6	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.9	4.0	3.6	3.6	3.8
Population (000s)	36,509	36,612	36,716	36,820	36,925	37,029	37,133	37,237	37,341	37,444	37,548	37,651	36,664	37,081	37,496
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.1*	*1.1*
Employment (000s)	18,288	18,351	18,408	18,465	18,517	18,569	18,624	18,677	18,729	18,779	18,830	18,882	18,378	18,597	18,805
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.2*	*1.1*
Labour force (000s)	19,617	19,669	19,715	19,755	19,792	19,823	19,860	19,895	19,936	19,979	20,025	20,071	19,689	19,843	20,003
	0.2	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.9	65.9	65.8	65.8	65.8	65.7	65.6	65.6	65.5	65.5	65.5	65.5	65.8	65.7	65.5
Unemployment rate (per cent)	6.8	6.7	]	6.5	6.4	6.3	6.2	6.1	6.1	6.0	6.0	5.9	5.0	6.3	6.0
Retail sales ($ millions)	544,993	548,612	552,481	556,796	561,126	565,426	569,722	574,100	578,398	582,590	587,038	591,155	550,720	567,593	584,795
	0.6	*0.7*	*0.7*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.8*	*0.7*	*2.8*	*3.1*	*3.0*
Housing starts (units)	173,433	176,633	178,749	183,024	181,974	183,954	185,834	189,234	194,903	198,426	200,564	203,301	177,960	185,249	199,298
	-3.4	*1.8*	*1.2*	*2.4*	*-0.6*	*1.1*	*1.0*	*1.8*	*3.0*	*1.8*	*1.1*	*1.4*	*0.1*	*4.1*	*7.6*

Shaded 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: July 16, 2015)

	Newfoundland and Labrador			Prince Edward Island			Nova Scotia			New Brunswick			Quebec		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**	**2014**	**2015**	**2016**	**2014**	**2015**	**2016**	**2014**	**2015**	**2016**
Agriculture	85	88	89	201	204	205	225	231	232	255	262	265	3,562	3,746	3,801
	-3.3	*3.5*	*0.9*	*3.7*	*1.7*	*0.5*	*-5.7*	*2.6*	*0.6*	*-3.2*	*2.8*	*1.1*	*-1.3*	*5.2*	*1.5*
Forestry	67	71	67	4	4	4	57	57	63	260	273	281	929	929	1,005
	-2.3	*6.2*	*-5.8*	*-12.2*	*3.9*	*-1.8*	*12.7*	*0.7*	*9.7*	*7.6*	*4.9*	*3.1*	*1.4*	*-0.1*	*8.2*
Agriculture and forestry support services	16	18	18	8	8	8	48	53	54	69	74	75	467	500	511
	-6.4	*10.3*	*2.6*	*23.8*	*4.5*	*2.2*	*5.5*	*8.7*	*2.6*	*7.7*	*7.3*	*2.2*	*10.3*	*7.1*	*2.2*
Fishing and trapping	229	242	243	91	97	96	479	507	503	151	160	158	83	96	96
	-8.2	*5.9*	*0.5*	*2.7*	*6.9*	*-0.7*	*11.0*	*5.8*	*-0.7*	*10.3*	*5.8*	*-1.2*	*16.9*	*15.6*	*-0.5*
Mining	8,258	8,194	8,104	2	2	2	1,262	972	909	354	400	479	4,273	4,473	4,632
	-7.2	*-0.8*	*-1.1*	*0.0*	*2.9*	*0.2*	*56.3*	*-23.0*	*-6.5*	*-10.0*	*12.9*	*19.8*	*19.4*	*4.7*	*3.6*
Manufacturing	992	1,057	1,078	459	477	488	2,704	2,805	3,035	2,899	2,985	3,066	44,631	45,370	46,574
	-8.4	*6.5*	*2.0*	*9.1*	*3.7*	*2.4*	*0.2*	*3.7*	*8.2*	*-3.6*	*3.0*	*2.7*	*3.1*	*1.7*	*2.7*
Construction	2,553	2,372	1,922	256	279	297	1,725	1,923	2,122	1,241	1,199	1,217	20,486	20,226	20,092
	-4.7	*-7.1*	*-18.9*	*-6.0*	*9.0*	*6.5*	*-4.0*	*11.5*	*10.4*	*-1.6*	*-3.4*	*1.5*	*-2.2*	*-1.3*	*-0.7*
Utilities	637	693	700	49	55	58	652	666	675	995	1,020	1,032	13,543	14,302	14,631
	-4.1	*8.8*	*1.1*	*-2.2*	*11.9*	*5.4*	*-2.3*	*2.1*	*1.3*	*4.8*	*2.5*	*1.2*	*-1.1*	*5.6*	*2.3*
Goods producing-industries	13,195	13,093	12,580	1,049	1,106	1,138	7,176	7,238	7,617	6,116	6,265	6,466	88,482	90,150	91,848
	-4.3	*-0.8*	*-3.9*	*1.7*	*5.3*	*3.0*	*4.0*	*0.9*	*5.2*	*-1.2*	*2.4*	*3.2*	*1.9*	*1.9*	*1.9*
Wholesale and retail trade	2,124	2,104	2,091	429	443	452	3,687	3,721	3,841	3,089	3,128	3,209	35,528	36,448	37,361
	2.6	*-1.0*	*-0.6*	*2.5*	*3.3*	*2.1*	*1.5*	*0.9*	*3.2*	*-0.6*	*1.3*	*2.6*	*1.2*	*2.6*	*2.5*
Transportation and warehousing	676	677	666	122	127	130	1,063	1,106	1,146	1,238	1,279	1,312	12,434	12,728	12,987
	-0.3	*0.1*	*-1.7*	*1.3*	*4.2*	*2.4*	*1.0*	*4.1*	*3.6*	*2.3*	*3.3*	*2.6*	*2.4*	*2.4*	*2.0*
Information and culture	588	585	588	132	131	133	1,077	1,074	1,079	807	804	807	10,168	10,133	10,217
	-2.2	*-0.5*	*0.5*	*-1.3*	*-0.3*	*0.9*	*-1.5*	*-0.3*	*0.5*	*-1.9*	*-0.4*	*0.4*	*-1.0*	*-0.3*	*0.8*
Finance, insurance, and real estate	3,270	3,358	3,425	939	964	985	7,398	7,546	7,716	4,914	4,998	5,105	56,973	58,785	60,478
	2.3	*2.7*	*2.0*	*1.5*	*2.6*	*2.2*	*2.7*	*2.0*	*2.2*	*1.1*	*1.7*	*2.1*	*1.8*	*3.2*	*2.9*
Community, business, and personal services	1,803	1,820	1,851	548	550	564	3,677	3,720	3,801	2,980	3,020	3,108	40,604	41,626	43,031
	1.0	*1.0*	*1.7*	*1.8*	*0.3*	*2.6*	*1.0*	*1.2*	*2.2*	*0.8*	*1.3*	*2.9*	*1.0*	*2.5*	*3.4*
Education	1,417	1,419	1,399	342	345	349	2,150	2,177	2,157	1,599	1,601	1,579	18,604	18,645	18,663
	0.5	*0.2*	*-1.4*	*0.3*	*0.8*	*1.2*	*-0.7*	*1.2*	*-0.9*	*-0.5*	*0.1*	*-1.3*	*0.9*	*0.2*	*0.1*
Health and social assistance	2,358	2,378	2,396	454	455	457	3,127	3,166	3,200	2,372	2,376	2,402	25,689	25,747	26,035
	0.8	*0.9*	*0.8*	*0.7*	*0.2*	*0.4*	*0.7*	*1.3*	*1.1*	*0.8*	*0.2*	*1.1*	*1.2*	*0.2*	*1.1*
Public administration and defence	1,979	1,969	1,976	615	621	625	4,122	4,150	4,175	2,953	2,969	2,981	23,287	23,369	23,390
	-0.5	*-0.5*	*0.4*	*-1.8*	*1.0*	*0.6*	*-0.2*	*0.7*	*0.6*	*1.0*	*0.5*	*0.4*	*1.7*	*0.4*	*0.1*
Service-producing industries	14,312	14,408	14,489	3,602	3,657	3,715	26,328	26,688	27,143	19,892	20,114	20,443	223,183	227,378	232,058
	1.6	*0.7*	*0.6*	*1.4*	*1.5*	*1.6*	*1.2*	*1.4*	*1.7*	*0.2*	*1.1*	*1.6*	*1.3*	*1.9*	*2.1*
All industries	26,924	26,919	26,486	4,644	4,755	4,845	33,480	33,902	34,736	26,063	26,434	26,964	311,825	317,686	324,065
	-2.9	*0.0*	*-1.6*	*1.3*	*2.4*	*1.9*	*1.6*	*1.3*	*2.5*	*0.0*	*1.4*	*2.0*	*1.4*	*1.9*	*2.0*

Shaded area represents forecast data.
All data are in millions of 2007 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 cont'd

(Forecast Completed: July 16, 2015)

	Newfoundland and Labrador			Prince Edward Island			Nova Scotia			New Brunswick			Quebec		
	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
Agriculture	89	90	90	207	211	212	235	240	243	269	275	279	3,877	3,955	4,041
	0.8	0.7	0.4	1.2	1.5	0.6	1.1	2.1	1.3	1.7	2.3	1.4	2.0	2.0	2.2
Forestry	66	66	66	4	4	4	66	66	66	291	304	303	1,084	1,108	1,131
	-1.6	0.9	-0.7	-0.7	0.9	-0.8	5.8	0.1	-0.7	3.6	4.3	-0.4	7.9	2.2	2.0
Agriculture and forestry support services	19	31	34	8	9	8	55	56	56	77	78	79	520	527	502
	2.1	65.3	11.7	1.7	1.4	-5.3	2.1	1.8	0.0	1.7	1.4	2.2	1.7	1.4	-4.7
Fishing and trapping	245	246	248	96	96	96	506	509	512	158	158	158	97	97	98
	0.6	0.6	0.5	0.0	0.0	-0.2	0.6	0.6	0.6	-0.1	0.0	0.1	0.6	0.6	0.6
Mining	7,993	8,027	9,576	2	2	2	864	864	841	522	526	531	4,723	5,151	5,556
	-1.4	0.4	19.3	1.1	1.1	1.1	-5.0	0.0	-2.6	9.0	0.7	1.0	2.0	9.1	7.9
Manufacturing	1,102	1,126	1,144	500	513	522	3,099	3,206	3,294	3,134	3,195	3,246	47,631	48,609	49,440
	2.2	2.1	1.6	2.6	2.4	1.9	2.1	3.5	2.7	2.2	2.0	1.6	2.3	2.1	1.7
Construction	1,719	1,554	1,479	311	320	326	2,155	2,160	2,187	1,375	1,637	1,644	20,623	21,104	21,021
	-10.6	-9.6	-4.8	4.6	3.0	1.8	1.5	0.3	1.2	13.0	19.0	0.4	2.6	2.3	-0.4
Utilities	723	761	769	61	63	64	684	692	701	1,048	1,062	1,074	14,963	15,264	15,539
	3.3	5.3	1.0	5.6	2.6	1.7	1.4	1.2	1.3	1.5	1.3	1.1	2.3	2.0	1.8
Goods-producing industries	12,315	12,248	13,753	1,170	1,197	1,214	7,688	7,818	7,925	6,767	7,128	7,207	94,026	96,324	97,836
	-2.1	-0.5	12.3	2.8	2.3	1.4	0.9	1.7	1.4	4.6	5.3	1.1	2.4	2.4	1.6
Wholesale and retail trade	2,114	2,148	2,175	459	466	470	3,880	3,913	3,931	3,284	3,361	3,387	38,393	39,242	39,871
	1.1	1.6	1.2	1.5	1.5	0.8	1.0	0.8	0.5	2.3	2.4	0.8	2.8	2.2	1.6
Transportation and warehousing	654	643	704	132	133	136	1,154	1,166	1,185	1,370	1,447	1,496	13,224	13,460	13,711
	-1.8	-1.5	9.4	1.1	1.3	1.7	0.7	1.0	1.6	4.4	5.6	3.4	1.8	1.8	1.9
Information and culture	592	598	597	134	135	136	1,084	1,088	1,084	809	811	808	10,305	10,372	10,395
	0.5	1.1	-0.3	0.9	0.8	0.6	0.4	0.4	-0.3	0.3	0.3	-0.4	0.9	0.7	0.2
Finance, insurance, and real estate	3,499	3,552	3,600	1,008	1,028	1,046	7,900	8,033	8,141	5,211	5,292	5,364	62,230	63,713	64,988
	2.2	1.5	1.3	2.3	2.0	1.7	2.4	1.7	1.3	2.1	1.6	1.4	2.9	2.4	2.0
Community, business, and personal services	1,881	1,920	1,930	578	591	599	3,885	3,963	4,061	3,172	3,217	3,236	44,266	45,348	46,453
	1.6	2.1	0.5	2.5	2.3	1.4	2.2	2.0	2.5	2.1	1.4	0.6	2.9	2.4	2.4
Education	1,385	1,387	1,393	354	354	354	2,132	2,130	2,120	1,561	1,560	1,556	18,977	19,140	19,298
	-1.0	0.2	0.4	1.4	0.1	-0.1	-1.2	-0.1	-0.5	-1.2	-0.1	-0.3	1.7	0.9	0.8
Health and social assistance	2,475	2,525	2,560	471	480	487	3,292	3,350	3,400	2,470	2,513	2,548	26,563	27,016	27,418
	3.3	2.0	1.4	3.0	1.9	1.5	2.9	1.8	1.5	2.8	1.7	1.4	2.0	1.7	1.5
Public administration and defence	1,994	2,012	2,016	631	637	645	4,220	4,267	4,323	3,006	3,032	3,062	23,678	23,954	24,180
	0.9	0.9	0.2	1.0	1.0	1.2	1.1	1.1	1.3	0.8	0.9	1.0	1.2	1.2	0.9
Service-producing industries	14,690	14,883	15,070	3,786	3,845	3,892	27,574	27,939	28,274	20,822	21,172	21,397	237,533	242,142	246,211
	1.4	1.3	1.3	1.9	1.5	1.2	1.6	1.3	1.2	1.9	1.7	1.1	2.4	1.9	1.7
All industries	26,422	26,549	28,242	4,949	5,034	5,099	35,238	35,733	36,174	27,643	28,354	28,659	331,718	338,625	344,206
	-0.2	0.5	6.4	2.1	1.7	1.3	1.4	1.4	1.2	2.5	2.6	1.1	2.4	2.1	1.6

Shaded area represents forecast data.
All data are in millions of 2007 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: July 16, 2015)

	Ontario			Manitoba			Saskatchewan			Alberta			British Columbia		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Agriculture	3,975	4,088	4,148	1,571	1,631	1,663	3,674	3,584	3,659	3,811	3,756	3,837	1,161	1,200	1,220
	−5.1	*2.8*	*1.4*	*−13.1*	*3.9*	*1.9*	*−17.1*	*−2.4*	*2.1*	*−9.1*	*−1.5*	*2.2*	*−1.9*	*3.3*	*1.7*
Forestry	389	488	538	29	30	35	57	60	70	423	451	509	1,654	1,614	1,591
	3.2	*25.4*	*10.3*	*−2.4*	*6.2*	*15.4*	*6.5*	*4.8*	*16.5*	*0.4*	*6.6*	*13.1*	*−8.1*	*−2.4*	*−1.5*
Agriculture and forestry support services	541	588	602	77	83	85	170	190	196	281	306	313	706	770	787
	14.0	*8.8*	*2.2*	*3.6*	*7.6*	*2.2*	*9.0*	*12.2*	*3.0*	*6.4*	*8.8*	*2.2*	*1.9*	*9.0*	*2.2*
Fishing and trapping	29	31	30	6	8	7	0	1	1	7	7	6	137	102	101
	16.8	*5.2*	*−1.1*	*0.0*	*19.6*	*−1.1*	*−75.0*	*383.0*	*−0.7*	*−61.8*	*0.4*	*−0.4*	*17.6*	*−25.9*	*−0.6*
Mining	8,634	8,920	9,227	3,038	2,947	2,966	13,170	12,982	13,290	83,791	82,482	84,442	12,266	12,039	12,392
	2.4	*3.3*	*3.4*	*−7.8*	*−3.0*	*0.7*	*7.2*	*−1.4*	*2.4*	*7.9*	*−1.6*	*2.4*	*4.6*	*−1.9*	*2.9*
Manufacturing	77,852	79,067	80,817	5,924	6,189	6,332	3,916	3,943	4,042	19,297	19,598	20,084	14,719	16,009	16,599
	3.8	*1.6*	*2.2*	*2.6*	*4.5*	*2.3*	*1.5*	*0.7*	*2.5*	*3.4*	*1.6*	*2.5*	*3.0*	*8.8*	*3.7*
Construction	32,626	33,622	34,479	3,710	3,826	4,057	4,733	4,371	4,696	32,930	30,493	28,998	16,483	15,969	17,703
	0.6	*3.1*	*2.6*	*1.8*	*3.1*	*6.0*	*−2.6*	*−7.6*	*7.4*	*2.2*	*−7.4*	*−4.9*	*3.1*	*−3.1*	*10.9*
Utilities	11,815	12,490	12,782	1,383	1,427	1,459	1,278	1,316	1,351	5,170	4,973	5,166	3,839	3,956	4,029
	0.9	*5.7*	*2.3*	*−0.2*	*3.2*	*2.2*	*3.8*	*3.0*	*2.7*	*4.1*	*−3.8*	*3.9*	*−1.4*	*3.0*	*1.9*
Goods-producing industries	136,253	139,686	143,016	15,519	15,921	16,385	26,927	26,378	27,235	145,106	141,461	142,751	50,554	51,247	54,011
	2.3	*2.5*	*2.4*	*−2.6*	*2.6*	*2.9*	*0.2*	*−2.0*	*3.2*	*4.4*	*−2.5*	*0.9*	*2.0*	*1.4*	*5.4*
Wholesale and retail trade	72,880	74,309	76,327	6,057	6,276	6,458	6,801	6,861	6,989	27,991	27,212	27,779	21,095	22,100	22,832
	4.3	*2.0*	*2.7*	*5.3*	*3.6*	*2.9*	*3.7*	*0.9*	*1.9*	*6.0*	*−2.8*	*2.1*	*4.4*	*4.8*	*3.3*
Transportation and warehousing	22,825	23,213	23,840	3,375	3,507	3,615	2,896	2,910	2,980	12,003	11,796	11,812	11,173	11,544	12,152
	3.9	*1.7*	*2.7*	*4.4*	*3.9*	*3.1*	*6.0*	*0.5*	*2.4*	*6.5*	*−1.7*	*0.1*	*3.6*	*3.3*	*5.3*
Information and culture	22,691	22,587	22,707	1,607	1,602	1,614	1,171	1,172	1,185	6,859	6,895	6,994	7,034	7,002	7,038
	0.4	*−0.5*	*0.5*	*−0.1*	*−0.3*	*0.7*	*0.0*	*0.1*	*1.1*	*0.7*	*0.5*	*1.4*	*−0.2*	*−0.5*	*0.5*
Finance, insurance, and real estate	143,664	148,183	152,976	9,866	10,157	10,476	8,231	8,420	8,699	43,143	44,307	45,939	49,683	51,618	53,269
	3.0	*3.1*	*3.2*	*2.9*	*2.9*	*3.1*	*3.0*	*2.3*	*3.3*	*3.9*	*2.7*	*3.7*	*3.7*	*3.9*	*3.2*
Community, business, and personal services	84,001	85,862	87,795	4,757	4,856	5,016	4,805	4,876	4,987	35,103	35,190	36,138	27,672	28,599	29,463
	2.1	*2.2*	*2.3*	*0.7*	*2.1*	*3.3*	*1.4*	*1.5*	*2.3*	*3.4*	*0.2*	*2.7*	*3.4*	*3.3*	*3.0*
Education	34,127	34,372	34,673	2,787	2,801	2,776	2,688	2,689	2,680	10,012	10,100	10,081	10,326	10,809	10,972
	0.5	*0.7*	*0.9*	*1.0*	*0.5*	*−0.9*	*2.8*	*0.0*	*−0.3*	*2.4*	*0.9*	*−0.2*	*−4.0*	*4.7*	*1.5*
Health and social assistance	41,048	41,421	42,117	4,315	4,412	4,474	3,455	3,528	3,604	13,518	13,816	14,340	13,753	13,997	14,286
	1.6	*0.9*	*1.7*	*2.0*	*2.3*	*1.4*	*1.3*	*2.1*	*2.2*	*3.6*	*2.2*	*3.8*	*2.1*	*1.8*	*2.1*
Public administration and defence	43,086	43,195	43,427	4,458	4,473	4,519	3,336	3,358	3,395	12,032	12,039	12,073	11,970	12,012	12,102
	0.5	*0.3*	*0.5*	*−0.8*	*0.4*	*1.0*	*1.0*	*0.6*	*1.1*	*1.7*	*0.1*	*0.3*	*0.4*	*0.4*	*0.8*
Service-producing industries	463,805	472,625	483,345	37,140	38,001	38,865	33,300	33,730	34,436	160,567	161,259	165,063	152,927	157,900	162,336
	2.3	*1.9*	*2.3*	*2.0*	*2.3*	*2.3*	*2.7*	*1.3*	*2.1*	*3.9*	*0.4*	*2.4*	*2.7*	*3.3*	*2.8*
All industries	600,575	612,828	626,878	52,874	54,137	55,465	60,095	59,976	61,539	305,523	302,570	307,664	203,335	209,001	216,201
	2.3	*2.0*	*2.3*	*1.1*	*2.4*	*2.5*	*1.4*	*−0.2*	*2.6*	*4.4*	*−1.0*	*1.7*	*2.6*	*2.8*	*3.4*

Shaded area represents forecast data.
All data are in millions of 2007 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 cont'd

(Forecast Completed: July 16, 2015)

	Ontario			Manitoba			Saskatchewan			Alberta			British Columbia		
	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
Agriculture	4,225	4,312	4,387	1,690	1,728	1,766	3,721	3,799	3,890	3,897	3,989	4,085	1,238	1,255	1,272
	1.9	*2.0*	*1.8*	*1.6*	*2.2*	*2.2*	*1.7*	*2.1*	*2.4*	*1.6*	*2.4*	*2.4*	*1.5*	*1.4*	*1.3*
Forestry	570	600	635	39	40	40	76	74	74	557	570	581	1,564	1,559	1,570
	6.0	*5.1*	*5.9*	*12.2*	*0.8*	*0.3*	*8.4*	*−2.6*	*−0.5*	*9.4*	*2.2*	*1.9*	*−1.7*	*−0.3*	*0.7*
Agriculture and forestry support services	612	613	607	86	87	90	201	205	222	318	323	332	801	812	857
	1.7	*0.2*	*−1.1*	*1.7*	*1.4*	*3.5*	*2.6*	*2.2*	*8.0*	*1.7*	*1.4*	*3.0*	*1.7*	*1.4*	*5.5*
Fishing and trapping	30	30	30	7	8	8	1	1	1	7	7	7	101	102	102
	−0.9	*0.3*	*−0.6*	*0.2*	*0.4*	*0.6*	*0.6*	*0.6*	*0.6*	*1.6*	*1.8*	*1.7*	*0.3*	*0.3*	*0.7*
Mining	9,391	9,444	9,566	3,061	3,024	2,950	13,276	13,155	12,878	85,921	87,371	88,720	13,029	14,265	14,185
	1.8	*0.6*	*1.3*	*3.2*	*−1.2*	*−2.5*	*−0.1*	*−0.9*	*−2.1*	*1.8*	*1.7*	*1.5*	*5.1*	*9.5*	*−0.6*
Manufacturing	81,844	83,532	85,206	6,441	6,551	6,640	4,136	4,230	4,317	20,561	21,019	21,432	17,030	17,513	18,061
	1.3	*2.1*	*2.0*	*1.7*	*1.7*	*1.4*	*2.3*	*2.3*	*2.1*	*2.4*	*2.2*	*2.0*	*2.6*	*2.8*	*3.1*
Construction	35,371	36,905	38,416	4,272	4,333	4,269	4,537	4,653	4,705	30,265	30,751	31,190	19,032	19,551	18,995
	2.6	*4.3*	*4.1*	*5.3*	*1.4*	*−1.5*	*−3.4*	*2.5*	*1.1*	*4.4*	*1.6*	*1.4*	*7.5*	*2.7*	*−2.8*
Utilities	13,068	13,332	13,581	1,488	1,517	1,580	1,387	1,420	1,454	5,300	5,427	5,553	4,131	4,228	4,323
	2.2	*2.0*	*1.9*	*2.0*	*2.0*	*4.1*	*2.7*	*2.4*	*2.3*	*2.6*	*2.4*	*2.3*	*2.5*	*2.4*	*2.2*
Goods-producing industries	145,504	149,167	152,822	16,867	17,069	17,124	27,265	27,467	27,470	146,222	148,852	151,296	56,515	58,873	58,954
	1.7	*2.5*	*2.5*	*2.9*	*1.2*	*0.3*	*0.1*	*0.7*	*0.0*	*2.4*	*1.8*	*1.6*	*4.6*	*4.2*	*0.1*
Wholesale and retail trade	77,285	78,579	80,236	6,603	6,692	6,741	7,149	7,275	7,399	28,547	29,230	29,988	23,550	24,334	24,796
	1.3	*1.7*	*2.1*	*2.3*	*1.3*	*0.7*	*2.3*	*1.8*	*1.7*	*2.8*	*2.4*	*2.6*	*3.1*	*3.3*	*1.9*
Transportation and warehousing	24,191	24,732	25,184	3,725	3,750	3,836	2,971	2,986	3,056	12,083	12,256	12,512	12,717	13,223	13,438
	1.5	*2.2*	*1.8*	*3.0*	*0.7*	*2.3*	*−0.3*	*0.5*	*2.3*	*2.3*	*1.4*	*2.1*	*4.7*	*4.0*	*1.6*
Information and culture	22,835	22,921	23,018	1,626	1,636	1,639	1,197	1,206	1,208	7,095	7,177	7,225	7,078	7,111	7,126
	0.6	*0.4*	*0.4*	*0.8*	*0.6*	*0.2*	*1.0*	*0.7*	*0.2*	*1.4*	*1.2*	*0.7*	*0.6*	*0.5*	*0.2*
Finance, insurance, and real estate	157,648	162,437	167,377	10,814	11,161	11,492	8,986	9,286	9,564	47,563	49,227	50,972	54,741	56,296	57,774
	3.1	*3.0*	*3.0*	*3.2*	*3.2*	*3.0*	*3.3*	*3.3*	*3.0*	*3.5*	*3.5*	*3.5*	*2.8*	*2.8*	*2.6*
Community, business, and personal services	90,076	92,174	94,487	5,160	5,320	5,469	5,096	5,239	5,399	37,166	38,134	39,276	30,627	31,784	31,880
	2.6	*2.3*	*2.5*	*2.9*	*3.1*	*2.8*	*2.2*	*2.8*	*3.1*	*2.8*	*2.6*	*3.0*	*3.9*	*3.8*	*0.3*
Education	34,700	34,786	34,793	2,774	2,805	2,831	2,693	2,737	2,777	10,146	10,339	10,554	11,149	11,295	11,403
	0.1	*0.2*	*0.0*	*−0.1*	*1.1*	*0.9*	*0.5*	*1.6*	*1.5*	*0.6*	*1.9*	*2.1*	*1.6*	*1.3*	*1.0*
Health and social assistance	42,599	43,587	44,488	4,610	4,697	4,778	3,700	3,761	3,817	14,916	15,363	15,799	14,571	14,940	15,280
	1.1	*2.3*	*2.1*	*3.0*	*1.9*	*1.7*	*2.7*	*1.6*	*1.5*	*4.0*	*3.0*	*2.8*	*2.0*	*2.5*	*2.3*
Public administration and defence	43,702	44,264	44,708	4,563	4,600	4,637	3,470	3,505	3,554	12,120	12,219	12,317	12,247	12,424	12,572
	0.6	*1.3*	*1.0*	*1.0*	*0.8*	*0.8*	*2.2*	*1.0*	*1.4*	*0.4*	*0.8*	*0.8*	*1.2*	*1.4*	*1.2*
Service-producing industries	492,518	502,963	513,774	39,792	40,580	41,341	35,178	35,911	36,690	169,540	173,850	178,549	166,901	171,628	174,488
	1.9	*2.1*	*2.1*	*2.4*	*2.0*	*1.9*	*2.2*	*2.1*	*2.2*	*2.7*	*2.5*	*2.7*	*2.8*	*2.8*	*1.7*
All industries	638,539	652,647	667,114	56,874	57,864	58,679	62,311	63,246	64,028	315,612	322,552	329,695	223,270	230,355	233,296
	1.9	*2.2*	*2.2*	*2.5*	*1.7*	*1.4*	*1.3*	*1.5*	*1.2*	*2.6*	*2.2*	*2.2*	*3.3*	*3.2*	*1.3*

Shaded area represents forecast data.
All data are in millions of 2007 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

October 2015

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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 Newfoundland Power's ("Newfoundland Power" or the "Company") rates.

In the Company's 2003/2004 General Rate Application, 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 Order No. P.U. 19 (2003), the Board approved the recommendations as presented in the evidence and the Mediation Report.

In Order No. P.U. 32 (2007), the Board stated that is was satisfied that Newfoundland Power's Cost of Service Study and methodology, along with the Marginal Cost Study, were appropriate to be used in establishing 2008 customer rates.

At Newfoundland Power's 2010 and 2013/14 General Rate Applications, the results of the Company's Cost of Service Studies and their use in establishing customer rates were not an issue and were accepted for use in establishing customer rates.

2.0 2014 *PRO FORMA* COST OF SERVICE STUDY

The Company has completed a 2014 *Pro forma* 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 is based on actual costs and revenue incurred in 2014, adjusted to reflect the increase in Purchased Power Costs as a result of Newfoundland and Labrador Hydro's ("Hydro's") Interim Rate increase, including RSP changes, effective July 1, 2015, and associated changes in Newfoundland Power's customer rates.

2.1 *Pro forma* Adjustments

The adjustments made to 2014 costs to reflect Hydro's interim rate increase included the following:

- Increasing the actual 2014 Purchased Power expense by $31,937,000.

- Decreasing revenue from the RSA rate adjustment by 111.29% to reflect an RSA factor change from .930 to - 0.105 ¢/kWh.

- Adjusting the actual revenue from base rates by:

Residential	5.24%
General Service Rate 2.1	5.24%
General Service Rate 2.3	5.24%
General Service Rate 2.4	5.24%
Street and Area Lighting	1.59%

- Adjusting the functional classification of the Purchased Power Costs to reflect the functional classification of the costs allocated to Newfoundland Power from Hydro's proposed 2015 test year cost of service study.

- Adjusting the classification of hydro production to match the system load factor as used in Hydro's proposed 2015 test year cost of service study.

2.2 Cost of Service Study Updates

The Cost of Service Study incorporates results from four specific studies which are updated every five years. These studies were updated based on 2012 actual costs and the results are included in the 2014 *Pro forma* Cost of Service Study. The four studies are:

- Customer Weighting Factor Study.
- Minimum System Analysis.
- Transformer Zero Intercept Analysis.
- General Plant Allocation Study.

Table 1 shows the impact that, in aggregate, the updates to the four studies had on the Company's revenue to cost ratios.

Table 1
Revenue to Cost Ratios
(Percentage)

	With Old Studies	**With New Studies**	**Variance**
Domestic	95.7	95.6	(0.1)
General Service			
(0-100kW)	107.8	108.6	0.8
(110-1000kVA)	112.2	111.9	(0.3)
(1000kVA and Over)	104.9	104.5	(0.4)
Street Lighting	102.4	103.4	1.0
Total	**100.0**	**100.0**	**0.0**

3.0 COST OF SERVICE STUDY RESULTS

Appendix A shows the detailed results of the Cost of Service Study.

The results of the Cost of Service Study have been divided into the following five groups of schedules.

Group 1: Results, pages 2 to 14 of 43.

Group 2: Functional Classification of Rate Base, pages 15 to 22 of 43.

Group 3: Functional Classification of Expenses, pages 23 to 29 of 43.

Group 4: Determination of Class Allocation Factors, pages 30 to 38 of 43.

Group 5: Miscellaneous Schedules, pages 39 to 43 of 43.

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). The major components 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

1 The purchased power expense excludes the portion of the expense that is attributed to funding Hydro's rural deficit.

include revenue that is either not generated from rates or is recovered through the RSA 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. The 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.

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 shows 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.[3]

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.

4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance and regulatory costs.

5. CDM Costs. These expenses include CDM general costs, CDM program costs and the costs associated with the Curtailable Service Option.

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 shows the customer statistics used to develop the allocation factors. The customer 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 shows the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1 CP).

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[2] The deductions from average rate base include the net CIAC (Schedule 2.3), the balance in the weather normalization reserve, other post-employment benefits, customer security deposits, accrued pension obligation, future income taxes, and the demand management incentive account. Since the balance in the weather normalization reserve is owed to customers, the balance is deducted from rate base. The additions to rate base include deferred charges (mostly pension costs), unamortized regulatory cost deferral, customer finance programs, cash working capital allowance, and materials and supplies allowance.

[3] The expense shown in the schedule excludes the portion of the purchased power cost associated with funding Hydro's rural deficit.

Schedule 4.2 shows the loss factors that are used as an input in calculating the energy and demand allocation factors.

Schedule 4.3 shows 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. 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 shows the reconciliation of the total expenses used in the Cost of Service Study to the 2014 Annual Report to the Board.

Schedule 5.3 shows the reconciliation of the total revenue used in the Cost of Service Study to the 2011 Annual Report to the Board.

Schedule 5.4 shows the reconciliation of the total return and taxes used in the Cost of Service Study to the 2014 Annual Report to the Board.

Cost of Service Study

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

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Notes:

1 - Within the Schedules rows and columns may not add due to rounding.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE
(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	Customer Acc. & Cust. Serv. O	Customer Specific P	Revenue Related Q
1	Purchase Power	375,291	148,346	227,727	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
2	Operating and Maintenance	85,403	5,737	5,415	9,007	6,984	10,726	5,282	3,125	831	2,681	1,320	7,832	892	4,145	18,895	64	2,467
3	Depreciation	49,288	3,647	2,794	6,415	4,002	9,879	4,866	3,462	920	2,470	1,217	3,565	1,453	2,220	2,328	49	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	477	0	0	477	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	219	0	0	0	0	146	72	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	2,448	0	0	0	0	1,312	646	0	0	328	162	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	87	0	0	0	0	0	0	0	0	0	0	87	0	0	0	0	0
8	Customer Service Fees	295	0	0	0	0	0	0	0	0	0	0	0	0	0	295	0	0
9	RSA Transfer - Energy Supply Cost Variance	1,838	0	1,838	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	RSA Transfer - PEVDA and OPEBS	1,724	118	109	198	150	269	132	84	22	67	33	150	22	79	288	1	0
11	RSA Transfer - Seasonal Rate Revenue Deferral	57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57
12	RSA Transfer - CDM Revenue Deferral	420	0	420	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Expense Credits	7,565	118	2,367	676	150	1,728	851	84	22	395	195	237	22	79	583	1	57
14	Subtotal Expenses	502,417	157,613	233,570	14,582	10,692	18,597	9,297	6,383	1,729	4,686	2,342	11,159	2,323	6,287	20,639	110	2,410
15	Return and Taxes	92,479	6,918	6,994	11,634	9,990	18,243	9,002	8,091	2,155	4,561	2,250	4,086	2,506	3,012	2,911	94	32
16	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	594,896	164,531	240,564	26,216	20,682	36,840	18,299	14,474	3,883	9,247	4,593	15,245	4,828	9,298	23,550	203	2,442

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FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 6. (Excludes the Rural Deficit of $59,488,702.)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 39 less Line 6. (Excludes non-regulated expenses of $2,800,957.)
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 9).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 14, Columns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 14).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 15).
8	Customer Service Fees	Functional Classification based on 100% Customer Service/ Customer Accounting.
9	RSA Transfer - Energy Supply Cost Variance	Classified 100% to Energy
10	RSA Transfer - PEVDA and OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Notes to Schedule 3.2)
11	RSA Transfer - Seasonal Rate Revenue Deferral	Assigned 100% as Revenue Related.
12	RSA Transfer - CDM Revenue Deferral	Classified 100% to Energy
13	Total Expense Credits	Sum of lines 4 through 12.
14	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 13. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
15	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 38. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
16	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	Total of Lines 14 and 15.

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE
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	Produced & Purchased	Transmission	Distribution										Customer		
							Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting	Acc. &	Specifically	Revenue
				Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned	Related
				A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	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	96,909	24,184	34,159	3,853	3,429	6,108	5,411	2,552	1,096	1,630	1,359	4,683	1,112	0	6,957	0	376
2	Domestic All Electric	1.1	298,194	88,786	113,303	14,147	10,210	18,186	10,481	7,599	2,123	4,855	2,632	9,071	2,154	0	13,475	0	1,173
3	Total Domestic	1.1	395,103	112,970	147,462	18,000	13,639	24,294	15,892	10,151	3,218	6,485	3,990	13,754	3,266	0	20,432	0	1,550
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	11,665	2,263	4,024	361	341	608	882	254	214	162	222	764	272	0	1,248	0	50
5	(10-100 kW)	2.1	61,215	17,154	27,925	2,733	2,292	4,082	676	1,706	246	1,090	170	643	834	0	1,390	0	275
6	Total (0-100 kW)	2.1	72,880	19,417	31,948	3,094	2,633	4,690	1,558	1,959	461	1,252	391	1,407	1,106	0	2,638	0	325
	(110-1000 kVA)	2.3																	
7	Primary (110-350 kVA)		1,460	410	768	65	58	104	2	0	0	0	0	0	42	0	4	0	7
8	Secondary (110-350 kVA)		38,819	10,605	19,779	1,690	1,506	2,682	65	1,121	39	716	16	84	201	0	133	0	183
9	Transmission (350-1000 kVA)		155	49	93	8	0	0	0	0	0	0	0	0	5	0	0	0	1
10	Primary (350-1000 kVA)		7,452	2,141	4,015	341	304	541	3	0	0	0	0	0	68	0	6	0	33
11	Secondary (350-1000 kVA)		28,538	7,877	14,691	1,255	1,118	1,992	16	832	10	532	4	0	50	0	33	0	127
12	Total (110-1000 kVA)	2.3	76,425	21,081	39,346	3,359	2,986	5,319	86	1,953	49	1,248	20	84	366	0	177	0	351
	(1000 kVA and Over)	2.4																	
13	Transmission		722	183	378	29	0	0	0	0	0	0	0	0	5	0	0	123	3
14	Primary		23,805	6,601	13,466	1,052	873	1,555	3	0	0	0	0	0	66	0	5	80	102
15	Secondary		12,288	3,284	6,662	523	434	774	2	323	1	207	1	0	19	0	5	0	52
16	Total (1000 kVA and Over)	2.4	36,815	10,069	20,507	1,604	1,308	2,329	5	323	1	207	1	0	91	0	11	203	157
17	**STREET LIGHTING**	4.1	13,673	994	1,301	158	117	208	758	87	153	56	190	0	0	9,298	292	0	59
18	Total		594,896	164,531	240,564	26,216	20,682	36,840	18,299	14,474	3,883	9,247	4,593	15,245	4,828	9,298	23,550	203	2,442

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ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE

NOTES:

Line No.	Category	
18	Total	Total Cost of Service shown in Schedule 1.1, Line 16.

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	34,159	41,756	20,617	0	0	376	96,909	9,691	2,475	(882)	108,193	416	107,777
2	Domestic All Electric	1.1	113,303	143,783	39,935	0	0	1,173	298,194	29,819	7,712	(2,912)	332,813	1,298	331,515
3	Total Domestic	1.1	147,462	185,540	60,552	0	0	1,550	395,103	39,510	10,187	(3,794)	441,006	1,715	439,292
	GENERAL SERVICE														
4	(0-10 kW)	2.1	4,024	3,989	3,602	0	0	50	11,665	1,166	332	(105)	13,059	56	13,003
5	(10-100 kW)	2.1	27,925	29,056	3,959	0	0	275	61,215	6,121	1,806	(723)	68,418	304	68,114
6	Total (0-100 kW)	2.1	31,948	33,045	7,561	0	0	325	72,880	7,288	2,138	(828)	81,477	360	81,117
	(110-1000 kVA)	2.3													
7	Primary (110-350 kVA)		768	637	48	0	0	7	1,460	146	44	(20)	1,630	7	1,623
8	Secondary (110-350 kVA)		19,779	18,318	540	0	0	183	38,819	3,882	1,200	(511)	43,390	202	43,188
9	Transmission (350-1000 kVA)		93	57	5	0	0	1	155	16	6	(2.4202)	174	1	173
10	Primary (350-1000 kVA)		4,015	3,327	77	0	0	33	7,452	745	220	(107)	8,310	37	8,273
11	Secondary (350-1000 kVA)		14,691	13,607	112	0	0	127	28,538	2,854	838	(388)	31,841	141	31,700
12	Total (110-1000 kVA)	2.3	39,346	35,946	782	0	0	351	76,425	7,642	2,308	(1,029)	85,346	389	84,957
	(1000 kVA and Over)	2.4													
13	Transmission		378	212	5	0	123	3	722	72	19	(10.1127)	804	3	800
14	Primary		13,466	10,082	74	0	80	102	23,805	2,380	672	(358)	26,499	114	26,386
15	Secondary		6,662	5,545	29	0	0	52	12,288	1,229	344	(174)	13,687	58	13,628
16	Total (1000 kVA and Over)	2.4	20,507	15,839	108	0	203	157	36,815	3,681	1,035	(542)	40,990	175	40,815
17	**STREET LIGHTING**	4.1	1,301	1,621	1,394	9,298	0	59	13,673	1,367	385	(33)	15,392	64	15,328
18	Total		240,564	271,990	70,398	9,298	203	2,442	594,896	59,489	16,052	(6,227)	664,211	2,703	661,508

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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.

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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	99,850	552	416	(9,691)	91,127	(882)	2,475	9,691	102,411	101,995
2	Domestic All Electric	1.1	311,245	1,751	1,298	(29,819)	284,476	(2,912)	7,712	29,819	319,095	317,797
3	Total Domestic		411,095	2,303	1,715	(39,510)	375,603	(3,794)	10,187	39,510	421,506	419,791
	GENERAL SERVICE											
4	(0-10 kW)	2.1	13,370	80	56	(1,166)	12,340	(105)	332	1,166	13,733	13,678
5	(10-100 kW)	2.1	73,014	330	304	(6,121)	67,526	(723)	1,806	6,121	74,730	74,426
6	Total (0-100 kW)	2.1	86,384	410	360	(7,288)	79,866	(828)	2,138	7,288	88,464	88,104
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		1,778	6	7	(146)	1,645	(20)	44	146	1,815	1,808
8	Secondary (110-350 kVA)		48,589	178	202	(3,882)	45,088	(511)	1,200	3,882	49,658	49,456
9	Transmission (350-1000 kVA)		235	1	1	(16)	221	(2)	6	16	240	239
10	Primary (350-1000 kVA)		8,938	23	37	(745)	8,252	(107)	220	745	9,111	9,073
11	Secondary (350-1000 kVA)		33,950	133	141	(2,854)	31,371	(388)	838	2,854	34,674	34,532
12	Total (110-1000 kVA)	2.3	93,488	341	389	(7,642)	86,577	(1,029)	2,308	7,642	95,498	95,108
	(1000 kVA and Over)	2.4										
13	Transmission		782	1	3	(72)	713	(10)	19	72	795	791
14	Primary		27,317	72	114	(2,380)	25,122	(358)	672	2,380	27,816	27,703
15	Secondary		13,939	48	58	(1,229)	12,816	(174)	344	1,229	14,214	14,156
16	Total (1000 kVA and Over)	2.4	42,037	120	175	(3,681)	38,650	(542)	1,035	3,681	42,825	42,650
17	**STREET LIGHTING**	4.1	15,504	0	64	(1,367)	14,201	(33)	385	1,367	15,920	15,856
18	Total		648,508	3,174	2,703	(59,489)	594,896	(6,227)	16,052	59,489	664,211	661,508

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REVENUE BY CLASS OF SERVICE

NOTE:

Column

A - From Booked Revenue and Bill Frequency Analysis adjusted for July 2015 rate change
B - From Booked Revenue and Bill Frequency Analysis adjusted for July 2015 rate change
C - Includes 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 adjusted for July 1, 2015 rate change.
G - From actual RSA booked and Bill Frequency Analysis adjusted for July 1, 2015 rate change.
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	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	419,791	439,292	95.6%
	GENERAL SERVICE				
2	(0-100 kW)	2.1	88,104	81,117	108.6%
3	(110 - 1000 kVA)	2.3	95,108	84,957	111.9%
4	(1000 kVA and Over)	2.4	42,650	40,815	104.5%
5	**STREET LIGHTING**	4.1	15,856	15,328	103.4%
6	Total		661,508	661,508	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	% Loader to be assigned to each Classified Cost Component 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 Cost Loader (cents/kWh) RSA H	Sales MWh I	RSA cents/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	9,691	376	(416)	2,475	12,126	96,533	12.56%	(882)	836,962	(0.105)
2	Domestic All Electric	1.1	29,819	1,173	(1,298)	7,712	37,406	297,021	12.59%	(2,912)	2,776,133	(0.105)
3	Total Domestic	1.1	39,510	1,550	(1,715)	10,187	49,531	393,554	12.59%	(3,794)	3,613,095	(0.105)
	GENERAL SERVICE											
4	(0-10 kW)	2.1	1,166	50	(56)	332	1,493	11,615	12.86%	(105)	98,589	(0.106)
5	(10-100 kW)	2.1	6,121	275	(304)	1,806	7,898	60,940	12.96%	(723)	684,210	(0.106)
6	Total (0-100 kW)	2.1	7,288	325	(360)	2,138	9,391	72,554	12.94%	(828)	782,799	(0.106)
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		146	7	(7)	44	189	1,454	13.01%	(20)	18,992	(0.106)
8	Secondary (110-350 kVA)		3,882	183	(202)	1,200	5,062	38,637	13.10%	(511)	484,612	(0.105)
9	Transmission (350-1000 kVA)		16	1	(1)	6	21	154	13.75%	(2.4202)	2,349	(0.103)
10	Primary (350-1000 kVA)		745	33	(37)	220	962	7,419	12.96%	(107)	99,212	(0.108)
11	Secondary (350-1000 kVA)		2,854	127	(141)	838	3,678	28,410	12.95%	(388)	359,967	(0.108)
12	Total (110-1000 kVA)	2.3	7,642	351	(389)	2,308	9,912	76,074	13.03%	(1,029)	965,132	(0.107)
	(1000 kVA and Over)	2.4										
13	Transmission		72	3	(3)	19	91	719	12.67%	(10.1127)	9,595	(0.105)
14	Primary		2,380	102	(114)	672	3,041	23,703	12.83%	(358)	332,798	(0.108)
15	Secondary		1,229	52	(58)	344	1,567	12,236	12.80%	(174)	163,236	(0.107)
16	Total (1000 kVA and Over)	2.4	3,681	157	(175)	1,035	4,699	36,658	12.82%	(542)	505,628	(0.107)
17	**STREET LIGHTING**	4.1	1,367	59	(64)	385	1,746	13,615	12.83%	(33)	31,886	(0.104)
18	Total		59,489	2,442	(2,703)	16,052	75,280	592,455	12.71%	(6,227)	5,898,540	(0.106)

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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

Line No.	Class of Service	Rate Code	Billing Statistics From Schedule 4.1: Energy Sales MWh A	Billing Statistics From Schedule 4.1: Average Number of Customers B	Billing Statistics From Schedule 4.1: Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	Unit Demand Costs: By Energy Sales cent/kWh E	Unit Demand Costs: By Billing Demand $/kW - $/kVA F	Unit Customer Costs: By Energy Sales cent/kWh G	Unit Customer Costs: 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	836,962	76,068	0	4.489	5.616	0.00	2.773	25.42	0.000	12.877
2	Domestic All Electric	1.1	2,776,133	147,342	0	4.490	5.832	0.00	1.620	25.43	0.000	11.942
3	Total Domestic	1.1	3,613,095	223,410	0	4.490	5.782	0.00	1.887	25.43	0.000	12.158
	GENERAL SERVICE											
4	(0-10 kW)	2.1	98,589	12,404	0	4.500	4.566	0.00	4.123	27.31	0.000	13.189
5	(10-100 kW)	2.1	684,210	9,502	2,582,616	4.505	4.797	12.71	0.654	39.22	0.000	9.955
6	Total (0-100 kW)	2.1	782,799	21,906	2,582,616	4.504	4.768		1.091	32.49	0.000	10.362
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		18,992	27	50,892	4.467	3.790	14.14	0.287	168.49	0.000	8.544
8	Secondary (110-350 kVA)		484,612	912	1,614,720	4.511	4.275	12.83	0.126	55.76	0.000	8.912
9	Transmission (350-1000 kVA)		2,349	2	12,372	4.383	2.737	5.20	0.251	245.58	0.000	7.371
10	Primary (350-1000 kVA)		99,212	43	262,824	4.463	3.788	14.30	0.088	168.42	0.000	8.339
11	Secondary (350-1000 kVA)		359,967	225	1,067,282	4.502	4.269	14.40	0.035	46.99	0.000	8.806
12	Total (110-1000 kVA)	2.3	965,132	1,209	3,008,090	4.501	4.210	13.51	0.092	60.95	0.000	8.803
	(1000 kVA and Over)	2.4										
13	Transmission		9,595	2	27,817	4.337	2.492	8.60	0.064	257.52	1.447	8.341
14	Primary		332,798	36	750,256	4.458	3.418	15.16	0.025	193.24	0.027	7.929
15	Secondary		163,236	34	441,957	4.497	3.832	14.15	0.020	79.51	0.000	8.349
16	Total (1000 kVA and Over)	2.4	505,628	72	1,220,030	4.468	3.534	14.65	0.024	141.32	0.045	8.072
17	**STREET LIGHTING**	4.1	31,886	10,655	0	4.500	5.736	0.00	4.933	12.30	32.902	48.070
18	Total		5,898,540	257,252	6,810,736	4.491	5.197		1.345	25.70	0.182	11.215

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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			Produced &	Produced &		Distribution											
			Purchased	Purchased	Transmission	Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting	Cust. Acc. &	Specifically
No.	Category	Total	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	176,253	79,173	97,080	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	23,119	23,119	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	124,815	0	0	124,009	0	0	0	0	0	0	0	0	0	0	0	806
	Substations																
4	Hydro Electric Production	9,723	4,368	5,356	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	854	854	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	53,450	0	0	53,211	0	0	0	0	0	0	0	0	0	0	0	238
7	Distribution	134,032	0	0	0	133,673	0	0	0	0	0	0	0	0	0	0	359
	Distribution																
8	Land and Land Clearing	42	0	0	0	0	21	11	0	0	5	3	0	0	2	0	0
9	Conductors, Poles and Fittings	611,231	0	0	0	0	312,035	153,689	0	0	78,009	38,422	0	0	29,076	0	0
10	Transformers	135,300	0	0	0	0	0	0	106,887	28,413	0	0	0	0	0	0	0
11	Services	96,808	0	0	0	0	0	0	0	0	0	0	96,808	0	0	0	0
12	Meters	26,433	0	0	0	0	0	0	0	0	0	0	0	26,433	0	0	0
13	Street lighting	20,206	0	0	0	0	0	0	0	0	0	0	0	0	20,206	0	0
14	Total Direct Utility Plant	1,412,264	107,513	102,436	177,220	133,673	312,056	153,699	106,887	28,413	78,014	38,425	96,808	26,433	49,284	0	1,403
	General Utility Plant																
15	Land and Land Clearing	4,589	130	124	701	343	801	395	274	73	200	99	249	68	127	999	5
16	Buildings	38,762	1,635	1,558	6,329	2,905	6,781	3,340	2,323	617	1,695	835	2,104	574	1,071	6,950	45
17	Computer Equipment	37,572	1,234	1,175	3,767	1,829	4,270	2,103	1,463	389	1,068	526	1,325	362	674	17,361	27
18	Misc Equipment	16,837	633	603	2,960	1,348	3,146	1,550	1,078	286	787	387	976	266	497	2,299	21
19	Transportation	27,162	477	454	3,742	2,701	6,305	3,106	2,160	574	1,576	776	1,956	534	996	1,775	29
20	Tele-communications	9,986	866	825	3,207	507	1,182	582	405	108	296	146	367	100	187	1,190	20
21	Total General Utility Plant	134,908	4,975	4,740	20,706	9,632	22,486	11,075	7,702	2,047	5,622	2,769	6,976	1,905	3,551	30,574	148
22	Total	1,547,173	112,489	107,176	197,926	143,305	334,542	164,774	114,589	30,460	83,636	41,194	103,784	28,338	52,835	30,574	1,551

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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										Cust. Acc. & Cust. Serv.	Specifically Assigned
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting		
						Demand	Demand	Customer	Demand	Customer'	Demand	Customer	Customer	Customer	Customer		
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	60,161	27,024	33,137	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	14,705	14,705	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	59,531	0	0	59,147	0	0	0	0	0	0	0	0	0	0	0	384
	Substations																
4	Hydro Electric Production	2,968	1,333	1,635	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	261	261	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	16,317	0	0	16,244	0	0	0	0	0	0	0	0	0	0	0	73
7	Distribution	40,917	0	0	0	40,807	0	0	0	0	0	0	0	0	0	0	109
	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	261,982	0	0	0	0	133,265	65,638	0	0	33,316	16,410	0	0	13,353	0	0
10	Transformers	36,632	0	0	0	0	0	0	28,939	7,693	0	0	0	0	0	0	0
11	Services	64,789	0	0	0	0	0	0	0	0	0	0	64,789	0	0	0	0
12	Meters	1,560	0	0	0	0	0	0	0	0	0	0	0	1,560	0	0	0
13	Street lighting	8,703	0	0	0	0	0	0	0	0	0	0	0	0	8,703	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	14,545	614	585	2,375	1,090	2,544	1,253	872	232	636	313	789	216	402	2,608	17
16	Computer Equipment	20,520	674	642	2,057	999	2,332	1,149	799	212	583	287	723	198	368	9,482	15
17	Misc. Equipment	9,999	376	358	1,758	800	1,868	920	640	170	467	230	580	158	295	1,365	13
18	Transportation	13,149	231	220	1,812	1,308	3,052	1,503	1,046	278	763	376	947	259	482	859	14
19	Tele-communications	7,997	693	660	2,568	406	947	466	324	86	237	117	294	80	150	953	16
20	Total	634,737	45,911	37,237	85,961	45,410	144,010	70,930	32,619	8,671	36,002	17,733	68,122	2,470	23,753	15,267	641

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. 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 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	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	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	802	0	0	797	0	0	0	0	0	0	0	0	0	0	0	5
	Substations																
4	Hydro Electric Production	74	33	40	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	404	0	0	402	0	0	0	0	0	0	0	0	0	0	0	2
7	Distribution	1,013	0	0	0	1,011	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	26,409	0	0	0	0	13,482	6,640	0	0	3,370	1,660	0	0	1,256	0	0
10	Transformers	1,859	0	0	0	0	0	0	1,469	390	0	0	0	0	0	0	0
11	Services	1,002	0	0	0	0	0	0	0	0	0	0	1,002	0	0	0	0
12	Meters	766	0	0	0	0	0	0	0	0	0	0	0	766	0	0	0
13	Street lighting	469	0	0	0	0	0	0	0	0	0	0	0	0	469	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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	32,806	39	40	1,200	1,011	13,482	6,640	1,469	390	3,370	1,660	1,002	766	1,726	0	10

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. 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.
	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 RATE BASE
(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	Revenue Related
1	Hydro Electric Production	116,092	52,149	63,943	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	8,414	8,414	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	65,283	0	0	64,862	0	0	0	0	0	0	0	0	0	0	0	422	0
	Substations																	
4	Hydro Electric Production	6,755	3,034	3,721	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	593	593	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	37,133	0	0	36,967	0	0	0	0	0	0	0	0	0	0	0	166	0
7	Distribution	93,115	0	0	0	92,866	0	0	0	0	0	0	0	0	0	0	249	0
	Distribution																	
8	Land and Land Clearing	42	0	0	0	0	21	11	0	0	5	3	0	0	2	0	0	0
9	Conductors, Poles and Fittings	349,248	0	0	0	0	178,769	88,051	0	0	44,692	22,013	0	0	15,724	0	0	0
10	Transformers	98,668	0	0	0	0	0	0	77,948	20,720	0	0	0	0	0	0	0	0
11	Services	32,019	0	0	0	0	0	0	0	0	0	0	32,019	0	0	0	0	0
12	Meters	24,873	0	0	0	0	0	0	0	0	0	0	0	24,873	0	0	0	0
13	Street lighting	11,503	0	0	0	0	0	0	0	0	0	0	0	0	11,503	0	0	0
14	Total Direct Net Utility Plant	843,738	64,190	67,664	101,829	92,866	178,791	88,061	77,948	20,720	44,698	22,015	32,019	24,873	27,228	0	836	0
	General Plant																	
15	Land and Land Rights	4,589	130	124	701	343	801	395	274	73	200	99	249	68	127	999	5	0
16	Buildings	24,217	1,022	974	3,954	1,815	4,236	2,087	1,451	386	1,059	522	1,314	359	669	4,342	28	0
17	Computer Equipment	17,052	560	533	1,709	830	1,938	955	664	176	484	239	601	164	306	7,879	12	0
18	Misc. Equipment	6,838	257	245	1,202	547	1,278	629	438	116	319	157	396	108	202	934	9	0
19	Transportation	14,013	246	234	1,931	1,393	3,253	1,602	1,114	296	813	401	1,009	276	514	916	15	0
20	Tele-communications	1,989	172	164	639	101	236	116	81	21	59	29	73	20	37	237	4	0
21	Total General Plant	68,699	2,388	2,275	10,136	5,030	11,742	5,783	4,022	1,069	2,935	1,446	3,643	995	1,854	15,307	73	0
22	Total Net Utility Plant	912,436	66,577	69,939	111,965	97,896	190,533	93,844	81,969	21,789	47,633	23,461	35,662	25,867	29,083	15,307	910	0
	Deductions from Rate Base																	
23	Contributions in Aid of Construction	32,806	39	40	1,200	1,011	13,482	6,640	1,469	390	3,370	1,660	1,002	766	1,726	0	10	0
24	Security Deposits	750	51	47	86	65	117	58	36	10	29	14	65	10	34	125	1	0
25	Post Retirement Benefits Liability	32,455	2,224	2,050	3,733	2,823	5,064	2,494	1,574	418	1,266	624	2,831	420	1,479	5,428	27	0
26	Future Income Taxes - Depreciation/CCA	8,341	609	639	1,023	895	1,742	858	749	199	435	214	326	236	266	140	8	0
27	Future Income Taxes - Pension/OPEBS	(6,140)	(421)	(388)	(706)	(534)	(958)	(472)	(298)	(79)	(239)	(118)	(536)	(79)	(280)	(1,027)	(5)	0
28	Demand Management Incentive Liability	87	87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Deductions	68,298	2,589	2,390	5,336	4,259	19,446	9,578	3,531	939	4,862	2,395	3,688	1,352	3,225	4,667	41	0
	Additions to Rate Base																	
30	Average Deferred Charges	102,687	7,036	6,487	11,812	8,931	16,021	7,891	4,981	1,324	4,005	1,973	8,956	1,328	4,681	17,175	86	0
31	Unamortized Cost Recovery Deferrals	8,308	569	525	956	723	1,296	638	403	107	324	160	725	107	379	1,389	7	0
32	Customer Financing Programs	1,250	86	79	144	109	195	96	61	16	49	24	109	16	57	209	1	0
33	Weather Normalization (hydro equal.)	(2,149)	0	(2,149)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Weather Normalization (Degree Day Norm.)	(1,201)	(120)	(126)	(201)	(176)	(343)	0	(147)	0	(86)	0	0	0	0	0	(2)	0
35	Cash Working Capital Allowance	6,404	444	437	690	525	945	465	299	79	236	116	511	81	270	968	5	332
36	Materials And Supplies	5,619	194	185	1,380	503	1,174	578	402	107	293	145	364	99	185	0	9	0
37	Total Additions	120,917	8,208	5,438	14,780	10,614	19,288	9,669	5,998	1,634	4,822	2,417	10,665	1,631	5,572	19,741	107	332
38	Total Average Rate Base	965,055	72,196	72,988	121,409	104,250	190,375	93,935	84,437	22,484	47,594	23,484	42,638	26,146	31,429	30,382	976	332

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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	Security Deposits	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
25	Post Retirement Benefits Liability	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
26	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
27	Future Income Taxes - Pension/OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
28	DMI Liability	Functional Classification Classified 100% to Produced and Purchased Demand.
29	Total Deductions	Total of Lines 23 through 28.
	Additions to Rate Base	
30	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
31	Unamortized Cost Recovery Deferrals	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
32	Customer Financing Programs	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
33	Weather Normalization (hydro equal.)	Classified 100% to Energy.
34	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions
35	Cash Working Capital Allowance	Functional Classification based on total operating and maintenance shown on Schedule 1.1, line 1 plus line 2.
36	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).
37	Total Additions	Total of Lines 30 through 36.
38	Total Rate Base	Line 22 less Line 29 plus Line 37.

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(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	434,780	-	434,780	-	434,780	-	434,780
PPDL	Nfld. Hydro - Secondary	-	-	-	-	-	-	-
	TOTAL PURCHASED POWER	434,780	-	434,780	-	434,780	-	434,780
	PRODUCTION							
Hydro	Hydro - Direct Operating and Maintenance	1,765	1,019	746	-	1,765	1,019	746
Hydro	Hydro - Water and Fuel - Lubricants	77	-	77	-	77	-	77
Hydro	Hydro - Supervision and misc.	677	490	187	-	677	490	187
Oth Prod	Other Production - Direct Operating and Maintenance	405	308	96	-	405	308	96
Oth Prod	Other Production - Fuel and Lubricants	61	-	61	-	61	-	61
	TOTAL PRODUCTION	2,985	1,817	1,168	-	2,985	1,817	1,168
Gen Sys Opr	SYSTEM OPERATIONS	1,215	1,112	103	-	1,215	1,112	103
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	706	7	698	-	706	7	698
Gen PTD	GENERAL OPERATIONS	5,088	4,480	608	-	5,088	4,480	608
	TOTAL MISC TECHNICAL OPERATING COSTS	7,009	5,600	1,409	-	7,009	5,600	1,409
Gen PTD	ENVIRONMENTAL COST	211	154	56	-	211	154	56
	SUBSTATIONS							
Subs	Direct O&M	2,733	2,021	712	-	2,733	2,021	712
	TRANSMISSION							
Transm	Direct O&M	1,342	317	1,025	-	1,342	317	1,025
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	2,833	2,577	256	-	2,833	2,577	256
Services	Direct O&M - Services	2,772	2,721	51	-	2,772	2,721	51
Strlgts	Direct O&M - Street Lights	1,481	823	659	-	1,481	823	659
Transf.	Direct O&M - Transformers	288	271	17	-	288	271	17
Meters	Direct O&M - Meters	112	80	31	-	112	80	31
Gen D	Direct O&M - Vegetation Management	891	142	749	-	891	142	749
Gen D	Power Quality	-	-	-	-	-	-	-
Gen D	Distribution Line Inspections	192	186	6	-	192	186	6
Gen D	Pre Issues	268	-	268	-	268	-	268
	TOTAL DISTRIBUTION	8,837	6,801	2,036	-	8,837	6,801	2,036
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,547	15	1,532	-	1,547	15	1,532
Gen Comm	Direct O&M - Supervisory Contol Systems	-	-	-	-	-	-	-
	TOTAL COMMUNICATIONS	1,547	15	1,532	-	1,547	15	1,532
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	3,652	3,223	429	23	3,629	3,202	427
Cust Acc	Credit, Collections & Cash Control	2,467	742	1,726		2,467	742	1,726

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(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.
Cust Acc	Inquiry	3,622	3,566	56		3,622	3,566	56
Cust Acc	Uncollectable Bills	1,490	-	1,490	-	1,490	-	1,490
CDM - GA	Conservation and Demand Management - General Activities	804	521	283		804	521	283
CDM - Prom	Conservation and Demand Management - Program Costs	4,855	1,049	3,807		4,855	1,049	3,807
CDM - DM	Curtailable Service Option	255	8	247		255	8	247
CDM - Prom	Conservation and Demand Management - Program Costs Deferred	(4,436)	(950)	(3,486)		(4,436)	(950)	(3,486)
	TOTAL CUSTOMER SERVICE	12,710	8,157	4,553	23	12,687	8,137	4,550
	FINANCE							
A&G	Finance	1,519	1,317	202		1,519	1,317	202
Labour Rela	Company Pension Scheme	11,806	(100)	11,906		11,806	(100)	11,906
Labour Rela	Other Post Retirement Benefits	10,968	-	10,968		10,968	-	10,968
	TOTAL FINANCE	24,293	1,217	23,076	-	24,293	1,217	23,076
A&G	CORPORATE COMMUNICATIONS	1,037	489	548	21	1,016	478	537
	MANAGEMENT INFORMATION SYSTEMS							
A&G	Computer Operations	829	724	105	-	829	724	105
A&G	Systems Development and Support	2,540	1,150	1,390	-	2,540	1,150	1,390
	TOTAL MIS	3,370	1,874	1,495	-	3,370	1,874	1,495
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	2,273	1,871	402	-	2,273	1,871	402
A&G	Employee Welfare & Coffee & Lunchroom Supplies	272	9	263	-	272	9	263
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	2,545	1,881	664	-	2,545	1,881	664
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	8,298	4,075	4,223	2,428	5,870	2,883	2,987
A&G	Misc. Costs - General	1,075	470	605	328	747	327	420
Ins & Dam.	Misc. Costs - Property Insurace & Public Liability (Not Insured)	1,599	97	1,503	-	1,599	97	1,503
Cust Acc	Mail Room	10	-	10	-	10	-	10
Revenue Related	PUB Assessments	881	-	881	-	881	-	881
A&G	Property Maintenance	1,582	163	1,419	-	1,582	163	1,419
A&G	Printing Services	240	148	92	-	240	148	92
	TOTAL ADMINISTRATION & MISCELLANEOUS	13,686	4,954	8,732	2,756	10,930	3,618	7,312
Vehicles	VEHICLE MAINTENANCE	1,910	-	1,910	-	1,910	-	1,910
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	518,994	35,296	483,697	2,801	516,193	33,930	482,263

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(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.

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
CDM - GA	Conservation and Demand Management - General Activities
CDM - Prom	Conservation and Demand Management - Program Costs
CDM - DM	Curtailable Service Option and Voltage Management
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.

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FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Catagory	Total	Produced & Purchased	Produced & Purchased	Transmission	Distribution										Customer	Specifically	Revenue
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting	Acc. &		
		Total	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned	Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	345,791	117,961	227,830	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	29,855	29,855	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Deer Lake Power Secondary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Demand Mangement Incentive Account	628	628	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Amortization of Degree Day Reserve	(983)	(98)	(103)	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
6	Sub Total	375,291	148,346	227,727	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
	Direct Operating & Maintenance Expense																	
7	Hydraulic Production	2,519	1,131	1,387	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Other Production	466	466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Transmission	1,342	0	0	1,333	0	0	0	0	0	0	0	0	0	0	0	9	0
	Substations																	
10	Hydarulic Plants	134	60	74	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Other Production	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	738	0	0	734	0	0	0	0	0	0	0	0	0	0	0	3	0
13	Distribution	1,849	0	0	0	1,844	0	0	0	0	0	0	0	0	0	0	5	0
	Distribution																	
14	Lines/poles/fittings	2,833	0	0	0	0	1,518	748	0	0	380	187	0	0	0	0	0	0
15	Services	2,772	0	0	0	0	0	0	0	0	0	0	2,772	0	0	0	0	0
16	Street Lights	1,481	0	0	0	0	0	0	0	0	0	0	0	0	1,481	0	0	0
17	Transformers	288	0	0	0	0	0	0	227	60	0	0	0	0	0	0	0	0
18	Meters	112	0	0	0	0	0	0	0	0	0	0	0	112	0	0	0	0
19	Customer Accounting	11,219	0	0	0	0	0	0	0	0	0	0	0	0	0	11,219	0	0
20	Subtotal Direct O&M	25,764	1,669	1,461	2,067	1,844	1,518	748	227	60	380	187	2,772	112	1,481	11,219	17	0
	General System Expenses																	
21	Related to Distribution	1,351	0	0	0	208	345	170	104	28	86	43	222	28	117	0	1	0
22	Related to Prod, Trans. & Distribution	6,004	536	491	810	640	1,064	524	319	85	266	131	685	87	360	0	6	0
23	Related to Vehicles	1,910	34	32	263	190	443	218	152	40	111	55	138	38	70	125	2	0
24	System Control Centre Expenses	1,215	126	116	453	80	133	65	40	11	33	16	86	11	45	0	0	0
25	General Communication Expenses	1,547	71	65	283	119	198	97	59	16	49	24	127	16	67	354	0	0
26	Subtotal General System Expenses	12,028	767	704	1,810	1,237	2,183	1,075	674	179	546	269	1,258	181	658	479	9	0
	Administration and General																	
27	Insurance, Injuries & Damages	1,599	117	123	196	172	334	164	144	38	83	41	63	45	51	27	2	0
28	Labour Related	22,774	1,560	1,439	2,620	1,981	3,553	1,750	1,105	294	888	438	1,986	294	1,038	3,809	19	0
29	Other Administration And General Expenses	16,889	1,157	1,067	1,943	1,469	2,635	1,298	819	218	659	324	1,473	218	770	2,825	14	0
30	Amortization - 2013 General Cost Deferral	1,586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,586
31	Amortization - 2011 and 2012 General Cost Deferrals	1,575	108	99	181	137	246	121	76	20	61	30	137	20	72	263	1	0
32	Amortization - 2012 Cost of Capital Deferral	829	57	52	95	72	129	64	40	11	32	16	72	11	38	139	1	0
33	PUB Assessments	881	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	881
34	Subtotal Administration and General Expenses	46,132	2,999	2,780	5,035	3,830	6,897	3,397	2,184	581	1,724	849	3,731	589	1,969	7,063	37	2,467
	CDM Activities																	
35	CDM - General Activities	804	55	51	92	70	125	62	39	10	31	15	70	10	37	134	1	0
36	CDM - Program Costs	420	0	420	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Curtailable Service Option	255	247	0	3	3	2	0	0	0	1	0	0	0	0	0	0	0
38	Subtotal CDM Activities	1,479	302	470	96	73	127	62	39	10	32	15	70	10	37	134	1	0
39	Total O&M (less RSA, MTA and Rural Deficit)	460,694	154,084	233,142	8,842	6,840	10,445	5,282	3,004	831	2,611	1,320	7,832	892	4,145	18,895	62	2,467

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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 regulatory deferrals (Lines 30, 31 & 32)
	Purchase Power Expense	Excludes the rural deficit of $59,488,702
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	Demand Mangement Incentive Account	Classification based on 100% Purchase Power Demand
5	Amortization of Degree Day Reserve	Functional Classification split based on Total Net Utility Plant (Schedule 2.4, Line 22) excluding Customer Classification Functions
6	Sub Total	Total of Lines 1 - 5.
	Direct Operating & Maintenance Costs	
7	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
8	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
9	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	
10	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
11	Other Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
12	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
13	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
14	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.
15	Services	Classified as shown in schedule 5.1 line 15.
16	Street Lights	Classified as shown in schedule 5.1 line 17.
17	Transformers	Classified as shown in schedule 5.1 line 14..
18	Meters	Classified as shown in schedule 5.1 line 16.
19	Customer Accounting	Classified 100% to Customer Accounting (Customer).
20	Subtotal Direct O&M	Total of Lines, 7 to 19.
	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 20). The weighting used is: 50.9% operating, and 49.1% capital.

	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	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	6.9%	6.3%	10.4%	8.2%	13.6%	6.7%	4.1%	1.1%	3.4%	1.7%	8.8%	1.1%	4.6%	23.1%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
21	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
22	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
23	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
24	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1, Line 29). Classification based on functional categories shown for general system expenses in columns B through N.
25	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1, Line 30). Classification based on functional categories shown for general system expenses in columns B through O.
26	Subtotal General System Expenses	Total of all Lines 21 to 25.
	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 20 plus 26). The weighting used is: 50.9% operating, and 49.1% capital.

Split for Administration and General

	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	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	6.9%	6.3%	11.5%	8.7%	15.6%	7.7%	4.9%	1.3%	3.9%	1.9%	8.7%	1.3%	4.6%	16.7%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
27	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
28	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
29	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
30	Amortization - 2013 General Cost Deferral	Assigned 100% as Revenue Related.
31	Amortization - 2011 and 2012 General Cost Deferrals	Functional Classification based on the Weighted Split for Administration and General.
32	Amortization - 2012 Cost of Capital Deferral	Functional Classification based on the Weighted Split for Administration and General.
33	PUB Assessments	Assigned 100% as Revenue Related.
34	Subtotal Administration and General	Total for Lines 27 to 33.
35	CDM - General Activities	Functional Classification based on the Weighted Split for Administration and General.
36	CDM - Program Costs	Functional Classification based 100% avoided energy supply cost
37	Curtaible Service Option	Functional Classification based on direct O&M classified to demand including purchase power.
38	Subtotal CDM Activities	Total for Lines 35 to 37
39	Total O&M	Totals of Lines 6, 20, 26, 34 and 38.

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution										Cust. Acc. & Cust. Serv.	Specifically Assigned
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting		
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	4,357	1,957	2,400	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	1,286	1,286	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	3,947	0	0	3,921	0	0	0	0	0	0	0	0	0	0	0	25
	Substations																
4	Hydro Electric Production	248	111	137	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	22	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	1,363	0	0	1,357	0	0	0	0	0	0	0	0	0	0	0	6
7	Distribution	3,419	0	0	0	3,410	0	0	0	0	0	0	0	0	0	0	9
	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	16,643	0	0	0	0	8,496	4,185	0	0	2,124	1,046	0	0	792	0	0
10	Transformers	3,783	0	0	0	0	0	0	2,989	794	0	0	0	0	0	0	0
11	Services	3,136	0	0	0	0	0	0	0	0	0	0	3,136	0	0	0	0
12	Meters	1,336	0	0	0	0	0	0	0	0	0	0	0	1,336	0	0	0
13	Street lighting	1,210	0	0	0	0	0	0	0	0	0	0	0	0	1,210	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	845	36	34	138	63	148	73	51	13	37	18	46	13	23	152	1
16	Computer Equipment	4,044	133	127	405	197	460	226	157	42	115	57	143	39	73	1,869	3
17	Misc. Equipment	709	27	25	125	57	132	65	45	12	33	16	41	11	21	97	1
18	Transportation	2,595	46	43	358	258	602	297	206	55	151	74	187	51	95	170	3
19	Tele-communications	346	30	29	111	18	41	20	14	4	10	5	13	3	6	41	1
20	Total	49,288	3,647	2,794	6,415	4,002	9,879	4,866	3,462	920	2,470	1,217	3,565	1,453	2,220	2,328	49

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. 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.
	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.

CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2013	2014	Average	2014 Energy Sales kWh	2014 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	76,549	75,586	76,068	836,962,000	0	43.0%	222,194	51.8%	184,447
2	Domestic All Electric	1.1	145,446	149,238	147,342	2,776,133,000	0	47.9%	661,608	46.8%	677,158
	GENERAL SERVICE										
3	(0-10 kW)	2.1	12,366	12,441	12,404	98,589,000	0	50.9%	22,111	65.2%	17,261
4	(10-100 kW)	2.1	9,432	9,572	9,502	684,210,000	2,582,616	52.6%	148,491	59.7%	130,831
	(110-350 kVA)	2.3									
5	Primary		27	26	27	18,991,539	50,892	56.7%	3,824	68.4%	3,170
6	Secondary		894	929	912	484,612,461	1,614,720	56.7%	97,568	68.4%	80,879
	(350-1000 kVA)	2.3									
7	Transmission		2	2	2	2,348,814	12,372	56.7%	473	68.4%	392
8	Primary		42	43	43	99,212,139	262,824	56.7%	19,975	68.4%	16,558
9	Secondary		209	241	225	359,967,046	1,067,282	56.7%	72,473	68.4%	60,076
	(1000 kVA and Over)	2.4									
10	Transmission		2	1	2	9,594,790	27,817	66.2%	1,655	74.4%	1,472
11	Primary		36	35	36	332,797,508	750,256	66.2%	57,388	74.4%	51,063
12	Secondary		34	34	34	163,235,702	441,957	66.2%	28,148	74.4%	25,046
13	**STREET LIGHTING**	4.1	10,579	10,731	10,655	31,886,000	0	48.0%	7,583	48.0%	7,583
14	Total		255,618	258,879	257,252	5,898,540,000	6,810,736	50.1%	1,343,490	53.6%	1,255,937

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ENERGY AND DEMAND LOSS FACTORS[1]

(Losses as a percentage of delivered)

Demand Loss Factors

Transmission	1.4632%
Primary	3.9532%
Secondary	2.9398%

Energy Loss Factors

Transmission	0.9580%
Primary	2.6120%
Secondary	2.3749%

(1) Based on a three year average (2012 to 2014)

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

				Customer Related Costs			Primary Lines			Secondary Lines			Transformers			Service Drops			Meters		
Line No.	Class of Service	Rate Code	Average Number of Customers A	Weighting Factor B	Weighted Number of Customer C	Allocation Factors D	Weighting Factor E	Weighted Number of Customer F	Allocation Factors G	Weighting Factor H	Weighted Number of Customer I	Allocation Factors J	Weighting Factor K	Weighted Number of Customer L	Allocation Factors M	Weighting Factor N	Weighted Number of Customer O	Allocation Factors P	Weighting Factor Q	Weighted Number of Customer R	Allocation Factors S
	DOMESTIC																				
1	Domestic Regular	1.1	76,068	1.0	76,068	29.541%	1.0	76,068	29.570%	1.0	76,068	29.582%	1.0	76,068	28.219%	1.0	76,068	30.718%	1.0	76,068	23.033%
2	Domestic All Electric	1.1	147,342	1.0	147,342	57.219%	1.0	147,342	57.276%	1.0	147,342	57.300%	1.0	147,342	54.659%	1.0	147,342	59.500%	1.0	147,342	44.615%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	12,404	1.1	13,644	5.299%	1.0	12,404	4.822%	1.0	12,404	4.824%	1.2	14,885	5.522%	1.0	12,404	5.009%	1.5	18,606	5.634%
4	(10-100 kW)	2.1	9,502	1.6	15,203	5.904%	1.0	9,502	3.694%	1.0	9,502	3.695%	1.8	17,104	6.345%	1.1	10,452	4.221%	6.0	57,012	17.263%
	(110-350 kVA)	2.3																			
5	Primary		27	1.6	43	0.017%	1.0	27	0.010%	-	-	0.000%	-	-	0.000%	-	-	0.000%	107.5	2,903	0.879%
6	Secondary		912	1.6	1,459	0.567%	1.0	912	0.355%	1.0	912	0.355%	3.0	2,736	1.015%	1.5	1,368	0.552%	15.1	13,771	4.170%
	(350-1000 kVA)	2.3																			
7	Transmission		2	1.6	3	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	167.2	334	0.101%
8	Primary		43	1.6	69	0.027%	1.0	43	0.017%	-	-	0.000%	-	-	0.000%	-	-	0.000%	107.5	4,623	1.400%
9	Secondary		225	1.6	360	0.140%	1.0	225	0.087%	1.0	225	0.088%	3.0	675	0.250%	-	-	0.000%	15.1	3,398	1.029%
	(1000 kVA and Over)	2.4																			
10	Transmission		2	1.6	3	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	177.6	355	0.108%
11	Primary		36	1.6	58	0.022%	1.0	36	0.014%	-	-	0.000%	-	-	0.000%	-	-	0.000%	125.7	4,525	1.370%
12	Secondary		34	1.6	54	0.021%	1.0	34	0.013%	1.0	34	0.013%	3.0	102	0.038%	-	-	0.000%	38.8	1,319	0.399%
13	**STREET LIGHTING**	4.1	10,655	0.3	3,197	1.241%	1.0	10,655	4.142%	1.0	10,655	4.144%	1.0	10,655	3.953%	-	-	0.000%	-	-	0.000%
14	Total		257,252		257,504	100.0%		257,248	100.0%		257,142	100.0%		269,566	100.0%		247,634	100.0%		330,256	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 - by 1.5% due to reported demand sales being based at secondary sales levels.
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	Secondary Energy Allocator				Primary Energy Allocator				Transmission Energy Allocator			
			Load at Meter kWh	Secondary Energy Loss Factor	Load at Secondary Input kWh	Secondary Allocation Factor	Load at Primary Output kWh	Primary Energy Loss Factor	Load at Primary Input kWh	Primary Allocation Factor	Load at Transmission Output kWh	Transmission Energy Loss Factor	Load at Transmission Input kWh	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	836,962,000	0.023749	856,839,011	15.398%	856,839,011	0.026120	879,219,645	14.227%	879,219,645	0.009580	887,642,570	14.200%
2	Domestic All Electric	1.1	2,776,133,000	0.023749	2,842,063,383	51.073%	2,842,063,383	0.026120	2,916,298,078	47.191%	2,916,298,078	0.009580	2,944,236,214	47.099%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	98,589,000	0.023749	100,930,390	1.814%	100,930,390	0.026120	103,566,692	1.676%	103,566,692	0.009580	104,558,861	1.673%
4	(10-100 kW)	2.1	684,210,000	0.023749	700,459,303	12.588%	700,459,303	0.026120	718,755,300	11.631%	718,755,300	0.009580	725,640,976	11.608%
	(110-350 kVA)	2.3												
5	Primary		-	0.023749	-	0.000%	19,276,412	0.026120	19,779,912	0.320%	19,779,912	0.009580	19,969,403	0.319%
6	Secondary		484,612,461	0.023749	496,121,523	8.916%	496,121,523	0.026120	509,080,217	8.238%	509,080,217	0.009580	513,957,205	8.222%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.023749	-	0.000%	-	0.026120	-	0.000%	2,384,046	0.009580	2,406,886	0.039%
8	Primary		-	0.023749	-	0.000%	100,700,321	0.026120	103,330,614	1.672%	103,330,614	0.009580	104,320,521	1.669%
9	Secondary		359,967,046	0.023749	368,515,904	6.622%	368,515,904	0.026120	378,141,539	6.119%	378,141,539	0.009580	381,764,135	6.107%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.023749	-	0.000%	-	0.026120	-	0.000%	9,738,711	0.009580	9,832,008	0.157%
11	Primary		-	0.023749	-	0.000%	337,789,471	0.026120	346,612,532	5.609%	346,612,532	0.009580	349,933,080	5.598%
12	Secondary		163,235,702	0.023749	167,112,387	3.003%	167,112,387	0.026120	171,477,363	2.775%	171,477,363	0.009580	173,120,116	2.769%
13	**STREET LIGHTING**	4.1	31,886,000	0.023749	32,643,261	0.587%	32,643,261	0.026120	33,495,903	0.542%	33,495,903	0.009580	33,816,793	0.541%
14	Total		5,435,595,210	0.023749	5,564,685,161	100.00%	6,022,451,365	0.026120	6,179,757,794	100.000%	6,191,880,552	0.009580	6,251,198,768	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 demand sales being 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

			Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
Line No.	Class of Service	Rate Code	Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	222,194	0.029398	228,727	17.632%	228,727	0.039532	237,769	16.579%	237,769	0.014632	241,248	16.554%
2	Domestic All Electric	1.1	661,608	0.029398	681,058	52.501%	681,058	0.039532	707,981	49.365%	707,981	0.014632	718,341	49.291%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	22,111	0.029398	22,761	1.755%	22,761	0.039532	23,661	1.650%	23,661	0.014632	24,007	1.647%
4	(10-100 kW)	2.1	148,491	0.029398	152,856	11.783%	152,856	0.039532	158,899	11.080%	158,899	0.014632	161,224	11.063%
	(110-350 kVA)	2.3												
5	Primary		-	0.029398	-	0.000%	3,881	0.039532	4,034	0.281%	4,034	0.014632	4,093	0.281%
6	Secondary		97,568	0.029398	100,436	7.742%	100,436	0.039532	104,407	7.280%	104,407	0.014632	105,934	7.269%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	480	0.014632	487	0.033%
8	Primary		-	0.029398	-	0.000%	20,274	0.039532	21,076	1.470%	21,076	0.014632	21,384	1.467%
9	Secondary		72,473	0.029398	74,603	5.751%	74,603	0.039532	77,553	5.408%	77,553	0.014632	78,687	5.399%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	1,679	0.014632	1,704	0.117%
11	Primary		-	0.029398	-	0.000%	58,248	0.039532	60,551	4.222%	60,551	0.014632	61,437	4.216%
12	Secondary		28,148	0.029398	28,976	2.234%	28,976	0.039532	30,121	2.100%	30,121	0.014632	30,562	2.097%
13	**STREET LIGHTING**	4.1	7,583	0.029398	7,806	0.602%	7,806	0.039532	8,115	0.566%	8,115	0.014632	8,233	0.565%
14	Total		1,260,176	0.029398	1,297,223	100.00%	1,379,627	0.039532	1,434,166	100.000%	1,436,325	0.014632	1,457,342	100.000%

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 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 being 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

			Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
Line No.	Class of Service	Rate Code	Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	184,447	0.029398	189,869	15.588%	189,869	0.039532	197,375	14.719%	197,375	0.014632	200,263	14.699%
2	Domestic All Electric	1.1	677,158	0.029398	697,066	57.227%	697,066	0.039532	724,622	54.039%	724,622	0.014632	735,225	53.963%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	17,261	0.029398	17,769	1.459%	17,769	0.039532	18,471	1.378%	18,471	0.014632	18,742	1.376%
4	(10-100 kW)	2.1	130,831	0.029398	134,677	11.057%	134,677	0.039532	140,001	10.441%	140,001	0.014632	142,050	10.426%
	(110-350 kVA)	2.3												
5	Primary		-	0.029398	-	0.000%	3,217	0.039532	3,344	0.249%	3,344	0.014632	3,393	0.249%
6	Secondary		80,879	0.029398	83,256	6.835%	83,256	0.039532	86,548	6.454%	86,548	0.014632	87,814	6.445%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	398	0.014632	404	0.030%
8	Primary		-	0.029398	-	0.000%	16,806	0.039532	17,471	1.303%	17,471	0.014632	17,726	1.301%
9	Secondary		60,076	0.029398	61,842	5.077%	61,842	0.039532	64,287	4.794%	64,287	0.014632	65,228	4.788%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	1,494	0.014632	1,516	0.111%
11	Primary		-	0.029398	-	0.000%	51,829	0.039532	53,877	4.018%	53,877	0.014632	54,666	4.012%
12	Secondary		25,046	0.029398	25,782	2.117%	25,782	0.039532	26,802	1.999%	26,802	0.014632	27,194	1.996%
13	**STREET LIGHTING**	4.1	7,583	0.029398	7,806	0.641%	7,806	0.039532	8,115	0.605%	8,115	0.014632	8,233	0.604%
14	Total		1,183,282	0.029398	1,218,068	100.00%	1,289,920	0.039532	1,340,913	100.000%	1,342,806	0.014632	1,362,454	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, 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 being 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	Distribution 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
	PURCHASED POWER														
1	Purchased from Nfld. & Lab. Hydro - Production	100.0%	34.1%	65.9%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	34.1%	65.9%											
	PRODUCTION														
4	Hydro	100.0%	44.9%	55.1%											
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%					67.0%	33.0%							
9	Secondary	100.0%									67.0%	33.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					67.0%	33.0%							
12	Secondary	100.0%									67.0%	33.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							79.0%	21.0%					
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%	92.1%	7.9%

Line No.		Total	Common	Specifically Assigned
19	Transmission	100.0%	99.35%	0.65%

Line No.		Total	Hydro	Other	Total	Transmission	Transmission	Distribution	Distribution	Cust. Acc.
20	Substations	100.0%	4.91%	0.43%	5.34%	26.87%	0.12%	67.49%	0.18%	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%	76.19%	19.05%	4.76%	100.0%	75.92%	18.98%	5.10%
22	Conductors, Poles and Fixtures	100.0%	76.19%	19.05%	4.76%	100.0%	75.92%	18.98%	5.10%

Line No.	General Plant Related Costs		Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	5.55%	15.37%	57.30%	21.78%
24	Gen. Prop. Buildings and Structures	100.0%	8.24%	16.42%	57.41%	17.93%
25	Computer Hardware and Software	100.0%	6.41%	10.08%	37.30%	46.21%
26	Gen. Prop. Other Equipment	100.0%	7.34%	17.68%	61.32%	13.65%
27	Transportation	100.0%	3.43%	13.86%	76.18%	6.53%
28	Communication - Total	100.0%	16.93%	32.30%	38.86%	11.91%
29	Communication - Scada	100.0%	19.92%	37.31%	42.77%	0.00%
30	Communication - Total Expenses	100.0%	8.78%	18.31%	50.04%	22.88%
31	Inventory	100.0%	6.73%	24.71%	68.56%	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's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified based on the results, before deficit allocation, of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
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 island interconnected system load factor from of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
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 NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
19	Transmission	Based on an analysis of 2012 year end fixed plant. Specifically Assigned based on 2008 Data.
20	Substations	Based on an analysis of 2012 year end fixed plant. Specifically Assigned based on 2008 Data.
	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 2014 General Property Fixed Plant Allocation Study (2012 Data)
24	Gen. Prop. Buildings and Structures	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
25	Computer Hardware and Software	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
26	Gen. Prop. Other Equipment	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
27	Transportation	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
28	Communication - Total	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
29	Communication - Scada	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
30	Communication - Total Expenses	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
31	Inventory	Based on an allocation of the year end inventory for 2014.

Newfoundland Power Inc.
2014 Pro forma 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, the amortization of the various Deferrals and *exclude* non-regulated expense, Rural Deficit and certain expenses associated recovered through other revenue (expense credits). Also, 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.

Total Reported Company Expenses	$486,815	(Return 20)
Add		
Depreciation Expense	49,288	(Return 6) (Schedule 1.1)
Curtailable Credits	242	(2014 Curtailable Service Option Report)
Amortization - 2013 General Cost Deferral	1,586	(Schedule 3.2, page 1 of 2 line 31)
Amortization - 2011 and 2012 General Cost Deferrals	1,575	(Schedule 3.2, page 1 of 2 line 32)
Amortization - 2012 Cost of Capital Deferral	829	(Schedule 3.2, page 1 of 2 line 33)
Pro forma Purchased Power Cost Increase	31,937	July 1, 2015 Rate Application dated June 12, 2015.
Less		
Deduct non-regulated expenses[1]	2,801	
Rural Deficit	59,489	(Schedule 1.1, page 2 of 2)
Expense Credits		
Wheeling Revenues	696	(Schedule 1.1)
Joint Use Revenues	2,448	(Schedule 1.1)
Revenue from Temp. Services and Reconnects	87	(Schedule 1.1)
Customer Service Fees	295	(Schedule 1.1)
RSA Transfer - Energy Supply Cost Variance	1,838	(Schedule 1.1)
RSA Transfer - PEVDA and OPEBS	1,724	(Schedule 1.1)
RSA Transfer - Seasonal Rate Revenue Deferral	57	(Schedule 1.1)
RSA Transfer - CDM Revenue Deferral	420	(Schedule 1.1)
Total Expense Credits	7,565	
Rounding	1	
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	502,417	

1. Non deductable Expenses (Return 13) + associated tax adjustment - Schedule 5.4

Newfoundland Power Inc.
2014 Pro forma 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 opposed 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	$619,504	(Return 14)
Add		
Pro forma RSA Billings	(6,227)	(Schedule 1.4)
Pro forma MTA Billings	16,052	(Schedule 1.4)
Curtailable Service Option Credits	242	(2014 Curtailable Service Option Report)
Pro forma Increase in Revenue from Base Rates	31,937	
Rounding	-	
Total Revenue from Final Rates	$661,508	(Schedule 1.4)

Newfoundland Power Inc.
2014 Pro forma 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 (After adjustment to Regulated Earnings)	$75,601	(Return 13)
Total Income Tax	10,795	(Return 22)
Total Return and Taxes	86,396	
Adjustments		
Tax Adjustment for non-regulated expenses[1].	812	
Tax Adjustment for Cost of Removal[2]	4,594	(Return 6, note 2)
Equity component of AFUDC	659	(Return 13 & 25)
Other Adjustments		
Interest on Tax	-	(Return 25)
Interest on security deposits	19	(Return 25)
Rounding	(1)	
Adjusted Return and Taxes (Schedule 1.1)	92,479	

Notes:

1 - Tax adjustment associated with non-regulated expenses from detail.

Non-regulated expenses	2,801	
Income taxes	812	
Rounding	-	
Non-regulated expenses net of taxes	1,989	Return 12

2 - The income tax is adjusted to reflect cost of removal is recorded net of taxes for regulatory purposes while the tax impact of the cost of removal is recorded as part of Total Income Tax on Return 22.

Customer Rate Impacts

October 2015

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Company performed impact analysis on the proposed rates relative to the current rates (effective July 1, 2015) for the Domestic class and each of the General Service classes.

This report summarizes the results of this analysis.

2.0 Domestic Methodology

2.1 General

There were approximately 223,000 customer accounts billed on the Domestic rate and approximately 1,900 customer accounts billed on the Domestic-Seasonal Optional rate at December 31, 2014. Evaluation of customer impacts of the proposed rate change for the Domestic class was based upon data from a representative sample of customers served under the Domestic rate.

The Domestic rate has the same energy price year-round. Therefore, the billing impacts can be determined based upon annual usage. The sample design methodology focused on ensuring that the annual usage distribution of the sample is reasonably representative of the annual usage of the population.

The Domestic customers identified in the Customer Service System with electricity as their primary heating source ("Domestic All-Electric") were analyzed separately from the Domestic customers identified as having some other heating source ("Domestic Regular"). The billing impacts were determined by applying the existing and proposed rates to the 2014 monthly electricity usage of a sample of 7,705 customers in the Domestic Regular subgroup and 15,716 in the Domestic All-Electric subgroup.[1]

The Domestic samples were selected using a systematic random sampling method to ensure the samples had comparable annual energy usage distributions to the subgroup populations.

The Domestic-Seasonal Optional Rate has approximately 1,900 participants. The impacts of the proposed customer rates were analyzed based upon the usage data of all customers on the rate option for the full year of 2014.

2.2 Sample Reliability

The Domestic samples provide a 95% confidence with ±1.7% relative accuracy on average monthly energy usage for the Domestic All-Electric subgroup and a 95% confidence with ±0.8% relative accuracy on average monthly energy usage for the Domestic Regular subgroup.

The 2014 average monthly energy usage for the Domestic Regular sample was 933 kWh; this compares to an actual average energy usage of 927 kWh per month for the population.

[1] The samples represent approximately 10% of the total customers in the respective subgroups.

The 2014 average monthly energy usage for the Domestic All-Electric sample was 1,661 kWh; this compares to an actual average monthly energy usage of 1,604 kWh for the population. The higher sample average energy use can be attributed to excluding customer accounts that were not active for all 12 months of 2014 in the sample selection process.[2]

The Domestic samples are reasonable for the purpose of evaluating the effects of the proposed rate changes on customer accounts.

3.0 General Service Methodology

There were 23,324 General Service customer accounts billed at year-end 2014.

Table 1 provides the breakdown of customer accounts, sales and revenue by rate class.

Table 1
General Service Classes

Rate	Rate Class	Customer Accounts	Sales (GWh)	Revenue ($000s)
2.1	0-100 kW (110 kVA)	22,013	782.8	82,080
2.3	110-1000 kVA	1,241	965.1	88,789
2.4	1000 kVA and Over	70	505.6	39,743
	Total General Service	**23,324**	**2,253.5**	**210,612**

The Company reviewed the billing impacts for all customer accounts that were on each rate for the full year of 2014.

[2] The population average use includes new connections during the year. Because two of the coldest winter months occur early in the year (i.e., January and February), the monthly average use for the population would not have included the coldest months for most new accounts. As a result, the average use would be expected to be lower for the population than the monthly average use for the sample because the sample only included customer accounts that were active for all 12 months in 2014. As temperature has less of an effect on average use for Domestic Regular customers, new customer connections would not have created a material difference on the average use between the sample and the population for that subgroup.

4.0 Customer Impacts

4.1 Domestic

Table 1 shows the customer bill impacts for Domestic rate customers under the proposed rate.

Table 1
Domestic 1.1
Customer Bill Impacts

Annual Impact (%)	% of Customers
Less than 3.6%	0.1
3.6%	99.2
More than 3.6%	0.7
% Receiving Increases	100.0

The proposed 3.6% increase in the Domestic rate has been applied equally to each rate component. For this reason, over 99% of all customers will receive annual bill impacts of 3.6%.

Customers not receiving a 3.6% increase are customers that (i) are charged the Basic Customer Charge Exceeding 200 Amp Service with low usage or (ii) are charged on the Domestic Seasonal rate. The minimum customer increase is 2.8%. The maximum customer increase is 4.1%.

The Basic Customer Charge Exceeding 200 Amp Service was designed to maintain a $5 charge above the Basic Customer Charge Not Exceeding 200 Amp Service.

The Domestic Seasonal rate was designed to maintain the existing energy charge adjustments as shown in Rate #1.1S.[3]

[3] See Schedule A to the Application, Rate #1.1S, page 2 of 8.

4.2 General Service

Table 2 shows the customer bill impacts for the Rate 2.1 under the proposed rate.

Table 2
Rate 2.1
Customer Bill Impacts

Annual Impact (%)	% of Customers
More than -10	1.4
-10 to -8	0.1
-8 to -6	1.5
-6 to -4	3.5
-4 to -2	0.2
-2 to 0	12.6
% Receiving Decreases	19.3
0 to 2	17.2
2 to 4	53.2
4 to 6	6.7
6 to 8	1.9
8 to 10	0.9
More than 10	0.8
% Receiving Increases	80.7

The range of decreases and increases primarily results from the Company's proposal to set the Rate 2.1 Basic Customer Charge (i) for unmetered service, at $4.00 less than the single phase service charge and (ii) for three phase service, at $6.00 greater than the single phase service charge. The overall increase of 3.1% has been applied equally to each other rate component to the extent possible.

Customers receiving a rate decrease of more than 6% are unmetered customers and three phase customers subject to the minimum monthly charge. Customers receiving a rate increase of more than 6% are three phase customers with low usage. The maximum bill increase experienced by any of these customers is less than $10.50 per month.

Table 3 shows the customer bill impacts for the Rate 2.3 under the proposed rate.

Table 3
Rate 2.3
Customer Bill Impacts

Annual Impact (%)	% of Customers
0 to 1	97.7
1 to 2	0.8
2 to 3	1.5
% Receiving Increases	100.0

The proposed rate provides a 0.6% average increase in customer rates. The increase has been applied equally to each rate component to the extent possible, except for the maximum monthly charge. The maximum monthly charge is the same for all General Service customers, which has been increased by 3.1%.

Table 4 shows the customer bill impacts for the Rate 2.4 under the proposed rate.

Table 4
Rate 2.4
Customer Bill Impacts

Annual Impact (%)	% of Customers
2 to 3	10.8
3 to 4	89.2
% Receiving Increases	100.0

The proposed rate provides a 3.1% average increase in customer rates. The increase has been applied equally to each rate component to the extent possible.

The minimum customer increase is 2.9%. The maximum customer increase is 3.2%.

Elimination of Unwarranted Three Phase Charge:
Required Regulation & Policy Changes

October 2015

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1.0 General

Historically, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") charged General Service customers an Unwarranted Three Phase Charge for the additional cost to provide three phase service which was not forecast to be collected through customer rates. Unwarranted Three Phase Charges are typically charged to, and paid by, General Service customers served under Rate 2.1

In this Application, the Company proposes the implementation of different Basic Customer Charges for General Service customers served under Rate 2.1. These different charges require a higher Basic Customer Charge for customers with three phase service. The higher monthly Basic Customer Charge for three phase service will recover the additional cost associated with providing three phase service.

If the proposed implementation of the changes to the Basic Customer Charge for Rate 2.1 is approved by this Board, the Unwarranted Three Phase Charge will no longer be necessary. So, the Company is proposing the elimination of the Unwarranted Three Phase Charge for General Service customers.[1]

To appropriately eliminate the Unwarranted Three Phase Charge for General Service customers, Newfoundland Power is proposing 3 modifications to existing regulatory policies. Firstly, it is proposed that Section of 5 (b) of the Company's Rates, Rules and Regulations be modified to reflect the elimination of the charge to General Service customers. Secondly, it is proposed that modifications be made to the Company's *Contribution in Aid of Construction Policy: Distribution Line Extensions and Upgrades To General Service Customers* ("the G.S. CIAC Policy") to reflect elimination of the charge.[2] Thirdly, it is proposed that a transition provision be made for customers that have paid an Unwarranted Three Phase Charge over the past 20 years.[3]

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[1] See *Section 6.4.2: Rate Structure Changes* at page 6-9 for more detail on the justification for implementation of different Basic Customer Charges for Rate 2.1 customers with unmetered, single phase and three phase service.

[2] The G.S. CIAC Policy also currently provides for an Unwarranted Three Phase Charge. In the future, the higher monthly Basic Customer Charge for three phase service will recover the additional cost associated with providing three phase service to all General Service customers. Accordingly, continuation of an Unwarranted Three Phase Charge in the Company's G.S. CIAC Policy would result in customers paying both a higher Basic Customer Charge for three phase service *and* an Unwarranted Three Phase Charge. This, in effect, would result in the customer paying twice for the additional cost (relative to single phase service) of the three phase service provided.

[3] Customers that have already paid an Unwarranted Three Phase Charge have, in effect, fully paid for the extra cost of three phase service over single phase service. For these customers, charging a higher Basic Customer Charge for three phase service would result in the customer paying twice for the additional cost (relative to single phase service) of the three phase service provided.

2.0 Proposed Changes to Regulation 5(b)

It is proposed that Clause 5(b) be modified to eliminate the need for an Unwarranted Three Phase Charge for General Service customers and to allow the Company to charge a Domestic customer the additional cost of three phase service as a special service under Regulation 9(c).[4]

The proposed wording for Regulation 5(b) is:

> *5(b) Service to customers who are provided Domestic Service shall be supplied at single phase 120/240 volts or as part of a multiunit building, at single phase 120/208 volts. The Company may, if requested by the customer, provide three phase service if a contribution in aid of construction is paid to the Company in accordance with Regulation 9(c).*

3.0 Proposed Changes to the G.S. CIAC Policy

The G.S. CIAC Policy was most recently approved by Order No. P.U. 27 (2005). The cost Appendices to the policy were most recently approved by Order No. P.U. 9 (2015). The G.S. CIAC Policy provides for unwarranted three phase charges to customers with estimated maximum Demand of under 75 kW.[5]

Modification of the G.S. CIAC Policy is required to (i) Section 3. Basic Investment, (ii) Section 5. Calculation of CIACs, and (iii) Appendix C.

The proposed changes to the G.S. CIAC Policy are shown in Schedule A to this report. Proposed additions to the G.S. CIAC Policy are shaded , deletions are ~~struck through~~.

4.0 Transitional Provisions

Since 1997, there have been approximately 250 customers who have paid a CIAC for an Unwarranted Three Phase Charge in accordance with Newfoundland Power's existing Rules and Regulations.[6] These customers are currently served under Rate 2.1. To ensure the elimination of the Unwarranted Three Phase Charge does not unduly penalize these customers, the Company proposes to allow these customers to pay the single phase basic customer charge as long as they continue to be supplied at the serviced premise for which an Unwarranted Three Phase Charge was paid.[7]

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4 The Company currently supplies approximately 100 Domestic customers who required a three phase service.

5 See Section 5(a)(i) of the *Contribution in Aid of Construction Policy: Distribution Line Extensions and Upgrades To General Service Customers* approved by Order No. P.U. 27 (2005).

6 Any CIAC for an Unwarranted Three Phase Service since 2013 is subject to a 24 month review. It is uncertain at this time the actual count of customers from 2013 and 2014 that will be subject to an Unwarranted Three Phase Charge until the 24 month review is complete.

7 Customers with an existing CIAC subject to a 24 month review after the proposed change becomes effective will receive a refund of any portion of their CIAC that is related to unwarranted three phase service.

NEWFOUNDLAND POWER INC.

CONTRIBUTION IN AID OF CONSTRUCTION POLICY:

DISTRIBUTION LINE EXTENSIONS AND UPGRADES

TO GENERAL SERVICE CUSTOMERS

1. THE POLICY: GENERAL

The Company will provide Line extensions or Upgrades for Permanent Service to General Service Customers without a CIAC when the cost to provide and maintain the Line extension or Upgrade will be recovered through electricity rates paid by those customers. Otherwise, a CIAC calculated in accordance with this policy will be required.

2. INTERPRETATION

Board means the Board of Commissioners of Public Utilities for Newfoundland and Labrador.

CIAC means a contribution in aid of construction.

Clearing Costs means the estimated costs for the required brush clearing along the route of a Line extension or Upgrade.

Company means Newfoundland Power Inc.

Cost per Metre means the average construction and maintenance cost per metre of Line extension or Upgrade as calculated by the Company and filed from time to time with the Board. For Upgrades, this includes only the costs associated with the primary conductor and related hardware. See Appendix A.

Demand means the quantity of electricity which is delivered to a customer. It is expressed in kilowatts or kilovoltamperes, either at a given point in time or averaged over a period of time.

Domestic Policy means the Company's policy entitled "Contribution in Aid of Construction Policy: Distribution Line Extensions to Domestic Customers" as approved by the Board.

Easement Costs means the estimated costs to complete a survey of the right-of-way for a Line extension or Upgrade, and includes the labour costs to complete the survey, survey document and drawing; travel costs; and registration fees.

General Service Customer means a customer eligible for Permanent Service or Temporary Service pursuant to any of Rate #'s 2.1, 2.2, 2.3 or 2.4 of the Company's Schedule of Rates, Rules & Regulations.

Line means an electrical distribution line and includes a Main Line or a Service Line.

Load Factor means the ratio of the average Demand in kilowatts supplied during a designated period to the maximum Demand in kilowatts supplied in that period. The average Demand is determined by dividing the energy consumption in kilowatt hours by 730 hours (if monthly) or by 8760 hours (if yearly).

Main Line means any Line required to supply electricity that is not a Service Line.

Municipality is as defined in the *Municipalities Act, 1999.*

Peak Demand means the maximum annual Demand that will be required by a customer.

Permanent Service means electrical service required for at least three years.

Schedule of Rates, Rules & Regulations means the schedule setting out the rates, rules and regulations relating to the Company's service as approved from time to time by the Board.

Service Drop means the span of Service Line from a customer's service entrance to the first pole that is connected to the Company's electrical system.

Service Line means any Line across private property or along a private road required to serve a single customer.

Temporary Service means a service that is required for a period of less than three years.

Upgrade means the upgrade of either (i) single phase Line to two phase, or (ii) single or two phase Line to three phase.

3. BASIC INVESTMENT

The Company's Basic Investment in a Line extension for Permanent Service to General Service Customers shall include:

(i) Up to 85 metres of Line[1], as measured from the point where the customer takes service, and all plant directly associated with that specific length of Line;

(ii) transformation for service up to 500 kVA where the required service voltage is one of the Company's standard service voltages and installation is in accordance with Company standards,[2]

(iii) secondary metering; and,

(iv) where the service location is on the side of the road opposite the Company's Line, the number of metres of Service Line equal to the width of the road right-of-way.

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1 The Line will be single phase or three phase depending on the requirements of the customer. ~~the line will be either three pase or single phase. Single phase, where the maximum Demand is estimated to be less than 75 kW. Otherwise, three phase. The Company may provide three phase service where maximum Demand is less than 75 kW, if requested by the customer, to the extent that such service is supported by projected revenue from the customer as set out in Regulation 5(b) of the Schedule of Rates, Rules & Regulations.~~

2 The Company may, on such conditions as it deems acceptable, provide transformation for services greater than 500 kVA as set out in Regulation 5(j) of the Schedule of Rates, Rules & Regulations.

4. ADDITIONAL INVESTMENT

(a) Additional Growth Based Investment

In addition to its Basic Investment, the Company will provide Additional Growth Based Investment in the form of single phase Main Line extensions for Permanent Service to General Service Customers. Additional Growth Based Investment will be provided if there is satisfactory evidence that future growth along the route of the Main Line extension will be sufficient to support the cost to construct and maintain the Main Line extension. The existence of a foundation for a new building along the route of the Main Line extension shall constitute satisfactory evidence of sufficient future growth.

For each such foundation, the Company will provide the number of metres of single phase Main Line, and all plant directly associated with that specific length of Main Line, that would be provided as Basic Investment under this policy or the Domestic Policy to a customer requiring service at the location of the foundation.

(b) Additional Load Based Investment

In addition to its Basic Investment and Additional Growth Based Investment, the Company will provide Additional Load Based Investment for Permanent Service to General Service Customers with a Demand exceeding 10 kW. Additional Load Based Investment will be provided to the extent that it will be recovered from revenue generated by the customer(s) requesting the Line extension or Upgrade. The amount of Additional Load Based Investment that will be supported by such revenue shall be determined by reference to the anticipated Load Factor and Peak Demand of the customer(s) in accordance with the Plant Support Table in Appendix B.

5. CALCULATION OF CIACs

(a) The cost of a Line extension or Upgrade for a General Service Customer shall, as applicable, be composed of the following:

~~(i) for a three phase Line extension or Upgrade to a customer with an estimated maximum Demand of under 75 kW, construction cost that is equal to the sum of (1) the number of metres of Line extension or Upgrade beyond the Service Drop multiplied by the applicable Cost per Metre as set out in Appendix A, and (2) the cost of the Service Drop, transformation and metering, based on the costs set out in Appendix C;~~

(i)~~(ii)~~ for all Line extensions or Upgrades, construction cost that is equal to the product of (1) the total number of metres of Line extension or Upgrade, and (2) the applicable Cost per Metre as set out in Appendix A;

(ii)~~(iii)~~ applicable Clearing Costs and Easement Costs;

(iii)~~(iv)~~ for an Upgrade, the costs associated with the replacement, transfer or installation of additional poles or anchors, including, without limitation, the costs set out in Appendix C.

(b) The CIAC for Line extensions or Upgrades for General Service Customers shall, subject to Clause 5 (c), be equal to the cost of the Line extension or Upgrade, as determined in accordance with Clause 5 (a), less the value of the Company's Basic and Additional Investment as provided for in Clauses 3 and 4.

(c) In cases where the Line extension or Upgrade will be shared by more than one customer, any CIAC required will be apportioned based on the length of the Line extension or Upgrade required to serve each customer. Where a customer is connected to a Line extension or Upgrade in respect of which a CIAC was paid within ten years from the date that the Line extension or Upgrade was placed in service, that customer shall pay a CIAC calculated as if service was connected to that customer when the Line extension or Upgrade was originally placed in service.

(d) For Upgrades, Clause 5 (c) does not apply to customers that require single phase service and are connected to a Line for which a CIAC was paid solely for an Upgrade.

(e) Detailed cost estimates will be used in place of the applicable Cost per Metre in determining the cost of a Line extension or Upgrade when either: (i) the cost of a Line extension or Upgrade calculated using the applicable Cost per Metre is estimated to be greater than $100,000, or (ii) an Upgrade is required from single phase to two phase Line.

(f) The Company's Additional Load Based Investment for a Permanent Service will be reduced by 2.5% for each year that the estimated life of the customer's operations is less than the depreciable life of the distribution plant used in the Line extension or Upgrade.

6. REFUNDS

(a) Subject to Clause 5 (d), where additional customers are connected to a Line extension or Upgrade within 10 years from the date that the Line extension or Upgrade was placed in service, the Company will refund all or part of a CIAC previously paid in respect of that Line extension or Upgrade by the existing customers. The amount of the refund to each existing customer will be the amount by which (i) the CIAC paid by that existing customer less any refunds already received thereon, exceeds (ii) the CIAC which would have been payable by that existing customer under Clause 5 if the additional customers had taken service at the time the Line extension or Upgrade was originally placed in service. A refund becomes due 90 days following the connection of the additional customer(s).

(b) Interest paid through the financing option outlined in Clause 8 is not refundable.

(c) The Company shall advise customers of its CIAC refund policy. The Company shall make all reasonable efforts to identify customer refunds. A refund that is past due will accrue interest at the rate prescribed in Clause 8 (b) commencing on the day following the day it became due.

7. SERVICE ENTRANCE LOCATIONS

Should a General Service Customer request the Company to attach to a service entrance that is not as close as practical to the distribution pole from which the Service Line is to be run, the customer will be required to pay the costs associated with any additional plant.

8. PAYMENT

(a) All CIACs shall be paid in advance of construction, except in the following cases:

(i) Federal or Provincial Government Departments may provide a purchase order;

(ii) General Service Customers, if approval has been given in advance by the Company's credit personnel, may provide a purchase order; and,

(iii) where approval has been given in advance by the Company's credit personnel, a customer may pay a CIAC on the following basis:

(1) $300 or ¼ of the CIAC, whichever is greater, as a down-payment in advance of construction; and,
(2) the balance together with interest by way of not more than 60 equal monthly installments of not less than $20 each.

(b) The interest rate applied to an unpaid CIAC balance shall be set at the time of the issuance of the customer’s CIAC quote. The rate shall be equal to the prime rate of the Company’s bankers as of the last day of the month immediately preceding the issuance of the CIAC quote to the customer, plus 3%.

(c) CIAC Installments shall be subject to the Company's credit policy. Default in payment of any installment on a CIAC shall, at the Company's option, render the unpaid balance immediately due and payable.

(d) Should a customer wish to prepay all or a portion of the unpaid balance, the Company will accept such pre-payment without bonus or penalty.

9. REVIEW OF CIACs

All CIACs collected from General Service Customers will be subject to a review after a period of 24 months from the date the service is made available. The purpose of the review is to determine the reasonableness of the original CIAC calculation. If the recalculated CIAC differs from that originally calculated by more than $100, such difference will, as applicable, be charged or refunded to the customer's electric service account.

10. BOARD APPROVALS

The Company shall apply to the Board for approval of:

(i) all Line extensions or Upgrades involving CIACs where the costs of the Line extension or Upgrade calculated pursuant to Clause 5 (a) are estimated to be greater than $50,000; and,

(ii) any deviations from this policy in the calculation of CIACs for Line extensions and Upgrades to General Service Customers.

NEWFOUNDLAND POWER INC.

DISTRIBUTION LINE COST PER METRE
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

TYPE OF CONSTRUCTION	COST / METRE [1] $
LINE EXTENSIONS	
SINGLE PHASE	**34**
THREE PHASE	**49**
UPGRADES [2]	
SINGLE PHASE TO THREE PHASE	**44**
TWO PHASE TO THREE PHASE	**26**

[1] These cost factors do not include any costs for clearing or obtaining easements. When clearing is required, an additional charge of $4.00 per metre will apply to the section of line beyond the distance of the Basic Investment. A $350 charge will be applied for each required easement beyond the distance of the Basic Investment.

[2] These costs include only the cost associated with primary conductors and related hardware in upgrades. For additional costs refer to Appendix C: Distribution Plant Upgrade Cost for General Service CIACs.

NEWFOUNDLAND POWER INC.
DISTRIBUTION PLANT SUPPORT TABLE
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

Annual Load Factor	Dollars per kW/kVA [1]
Less than 5%	**92**
5%-9.9%	**133**
10%-14.9%	**146**
15%-19.9%	**166**
20%-24.9%	**179**
25%-29.9%	**187**
30%-34.9%	**198**
35%-39.9%	**211**
40%-44.9%	**222**
45%-49.9%	**231**
50%-54.9%	**238**
55%-59.9%	**245**
60%-64.9%	**256**
65%-69.9%	**261**
70% and Over	**266**

[1] The Additional Load based Investment, which applies to customers with a maximum annual demand exceeding 10 kW, will be determined by multiplying (i) the estimated maximum annual demand, less 10 kW, and (ii) the appropriate dollars per kW/kVA.

NEWFOUNDLAND POWER INC.
DISTRIBUTION PLANT UPGRADE COST
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

TYPE OF TRANSFER OR REPLACEMENT		COST[1] ($)
REPLACE POLES - UP TO 45'		2,180
ADDITIONAL POLES		1,290
DISTRIBUTION SECONDARY PER POLE / SPAN		
Transfer Only		770
Replace Conductor		940
SERVICE DROP PER POLE / SPAN		
Transfer Only		80
Replace Conductor		140
TRANSFORMER MOUNTINGS		
Single Transformer		920
Two or Three Transformers		2,250
POLE GUY		
Transfer Only		40
Replace Guy		70
REPLACE ANCHOR		560
ADDITIONAL ANCHOR		300
STREETLIGHTING - TRANSFER SINGLE FIXTURE		230
STREETLIGHTING DUPLEX PER POLE / SPAN		
Transfer Only		80
Replace Conductor		130
~~UNWARRANTED THREE PHASE CONSTRUCTION COST~~	-	-
~~(SERVICE DROP, METER & TRANSFORMER)~~	-	-
~~New Service~~	-	~~8,400~~
~~Upgrade Single Phase to Three Phase~~	-	~~4,800~~
~~Upgrade Two Phase to Three Phase~~	-	~~2,100~~
-	-	-
~~VALUE OF SINGLE PHASE BASIC INVESTMENT~~	-	~~6,000~~

[1] Includes all overheads.

Curtailable Service Option Review

October 2015

Table of Contents

1.0 Executive Summary

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") reviewed its Curtailable Service Option (the "Option") in 2014.

The purpose of the review was to assess the effectiveness of the Option and identify changes that might improve the attractiveness of the Option to the Company's customers. A significant impetus for the review were the supply issues and power outages encountered on the Island Interconnected system in January 2014.[1]

The review included:

(i) a scan of similar curtailable, or interruptible, programs offered in other Canadian jurisdictions; and
(ii) consultations with current Option customers to determine what changes could improve the Option.

As a result of Newfoundland Power's review, changes modifying penalty provisions and broadening Option eligibility are proposed. The proposed changes are designed to promote continued reliable curtailment capability for the Island Interconnected system. The proposed changes are also reasonably consistent with current Canadian regulatory practice.

2.0 Newfoundland Power's Curtailable Service Option

The Option is available to customers served under General Service Rates 2.3 and 2.4 that have a billing demand of at least 300 kW. Every Option customer must agree to curtail its demand by between 300 kW and 5,000 kW.[2]

The Option provides an annual credit (a "curtailment credit") to customers for reducing their electrical demand at the request of Newfoundland Power during the winter peak season.[3]

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1 Following the supply shortage and power outages event in January 2014, it was evident that increasing the amount of contracted load curtailment would benefit the Island Interconnected system. For example, the Board's consultant in its investigation into the January 2014 supply shortage and power outage event, The Liberty Consulting Group, in their *Interim Report* of April 24, 2014 stated on page 37: "Additional interruptible load, further load reductions via curtailment arrangements, and added conservation efforts are all avenues that should be pursued. We would not expect, however, that any of these individual measures will make a very large contribution, although collectively the effects will be welcome. When a borderline situation exists, every saved MW can be of real value; hence, such efforts should be encouraged. We observe that the effects may prove small compared to those of new generation."

2 This translates to between 330 kVA and 5,500 kVA.

3 The winter peak season is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a customer to curtail must be demonstrated to the Company's satisfaction prior to the customer's availing of this rate option.

Sixteen general service customers participated in the Option during the 2014-2015 winter season, providing average curtailed load of approximately 10.4 MW. Over the past 5 winter seasons, Option customers have successfully curtailed load 92% of the times they were requested to do so by Newfoundland Power.[4]

Appendix A shows the Company's current Curtailable Service Option.

3.0 Customer Consultation

In June 2014, Newfoundland Power consulted current Option customers to solicit feedback on the Option.[5]

A primary customer concern related to the number of curtailment requests in the 2013-2014 winter season. This has largely been addressed by Order No. P.U. 47 (2014). This Order effectively restricts the Company's requests to curtail to circumstances where there is a capacity constraint on the Island Interconnected system. The practical effect of the Order is to reduce the number of Newfoundland Power requests for customers to curtail so the Company can manage its power supply costs.

The other suggestions received from customers related to: (i) relaxing penalty provisions of the Option, (ii) permitting grouped curtailment and (iii) increasing the value of the credit.

4.0 Comparable Canadian Service Offerings

Four Canadian electric utilities other than Newfoundland Power have curtailable service offerings at a distribution level. They are Nova Scotia Power, Hydro Quebec, Manitoba Hydro and SaskPower.[6]

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4 Detailed results for the 2014-2015 winter peak season were submitted to the Board in the Company's 2015 Curtailable Service Option Report dated April 30, 2015.

5 This consultation supplemented the Company's routine practice of contacting all Option participants prior to the winter season to confirm participation and verify curtailment compliance processes. The consultation included 13 of the 17 Option customers during the 2013-2014 winter season and a former Option customer that chose not to participate during the 2013-2014 winter season.

6 No comparable rate options existed at the distribution service level in Prince Edward Island, New Brunswick, Ontario, Alberta and British Columbia.

Table 1 summarizes key features of comparable curtailable service offerings of Canadian electrical utilities.

Table 1
Canadian Electric Distribution Utilities
Curtailable Service Offerings
Key Features
(kW or kVA)[7]

	Newfoundland Power	**Nova Scotia Power**	**Hydro Quebec[8]**	**Manitoba Hydro[9]**	**Sask Power[10]**
Minimum Demand Eligibility[11]	300	2,000	1,000	5,000	5,000
Minimum Curtailment	300	2,000	200	5,000	5,000
Annual fixed credit ($)	29.00/kVA	41.16/kVA	13.00/kW	28.22/kW	20.00/kW
Variable credit ($/kWh)	-	0.004[12]	0.20 - 0.30[13]	-	0.15[14]
Notification Period	1 hour	10 minutes	2 hours	5 minutes	2 hours
Eligibility Termination	3 failures	-[15]	4 failures	3 failures	-[16]

Newfoundland Power's Option has the lowest minimum demand eligibility for participation. The Company's Option has the 2nd lowest minimum curtailment requirement. These features are

7 All amounts are in kW except Nova Scotia Power, which are shown in kVA. Although different units, the amounts are comparable as the difference between a kW and a kVA is not material.
8 Option I under the interruptible electricity options for medium-power customers is shown. Hydro Quebec provides several interruptible rates for different classes of customers. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
9 Option A interruptible rate option is shown. Manitoba Hydro provides several interruptible rate options. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
10 Program Offer 2 is shown. SaskPower provides 2 interruptible rate options. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
11 Eligibility to participate in a curtailable rate option can be based upon a customer's maximum demand. Practically, a customer with a higher maximum demand will tend to have a higher ability to curtail, whether by using back-up generation or by reducing its operational load.
12 Nova Scotia Power provides a separate energy charge, which is applied to all kWhs, for its interruptible customers as part of its Large Industrial Tariff (2,000 kVA and over). The energy charge for interruptible customers is $0.004/kwh less than the energy charge for firm customers.
13 The variable credit is based on the duration of the curtailment.
14 The variable credit is based on the kWh reduction during curtailment.
15 Nova Scotia Power requires 5 year notice if a customer decides not to be served under the interruptible rate option.
16 SaskPower does not specify the number of customer curtailment failures which will lead to termination of participation.

a reflection of the Company's customer base.[17]

Newfoundland Power has the 2nd highest fixed curtailment credit amongst comparable service offerings. Newfoundland Power's Option does not include a variable credit.

The 1 hour notification period for Newfoundland Power's Option is within the 5 minute to 2 hour range for comparable Canadian curtailable service options.

5.0 Newfoundland Power Proposals

5.1 Penalty Provisions

Of the 13 Newfoundland Power customers consulted on the Option, 8 suggested changes to the penalty clause.[18] Generally, the penalty clause was seen by customers to be too punitive.

Currently, an Option customer's curtailment credit is reduced by 50% as a result of the first failure to curtail. Each additional failure to curtail results in a further 25% reduction in the curtailment credit. After 3 failures, the customer is no longer entitled to a credit or service under the Option.[19]

Newfoundland Power proposes to implement a two tiered approach for failing to curtail. This approach incorporates suggestions from customers received during the consultation phase. The proposed changes to the Failure to Curtail clause of Option are:

1. The maximum number of failures to curtail in a winter period will be increased from 3 to 4.
2. Tier 1 will include the first 5 curtailment requests in the winter period. For each failure to curtail in Tier 1 the Curtailment Credit will be reduced by 25%.
3. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested.

[17] Less than 0.01% of Newfoundland Power's customers are served under Rate 2.4 (1,000 kVA and over). Thirteen of the current 16 Option customers are served under Rate 2.3 (110-1,000 kVA).

[18] Seven of these customers are represented by a single entity.

[19] See Appendix A for Newfoundland Power's current Curtailable Service Option rate. The "Failure to Curtail" clause is the penalty clause.

4. Tier 2 will include all remaining curtailment requests in the winter period. For each failure to curtail in Tier 2 the Curtailment Credit will be reduced by 12.5%.[20]

In the past 2 winter seasons, there were 9 Option requests as a result of supply shortage events.[21] There remains a high risk of supply shortage events until the Island Interconnected system is interconnected to the North American grid.[22] A higher number of allowed failures increases the probability of load curtailment being available in winter periods that involve frequent, or extended, supply shortage events.

5.2 Grouped Curtailment

In customer consultations on the Option, it was indicated that Newfoundland Power should consider allowing smaller facilities owned by the same person to aggregate their load curtailment. This would allow the facilities to collectively meet the 300 kW minimum demand eligibility and curtailment requirements. For example, an owner of 3 facilities, each able to curtail 100 kW, should be eligible to participate in the Option.

Newfoundland Power proposes to allow grouped curtailment to achieve the minimum eligibility requirement of 300 kW upon certain conditions. Each facility would be required to curtail a minimum of 100 kW.[23] The group would be treated as one customer for curtailment purposes

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[20] For example, if a customer is eligible to receive a $100,000 curtailment credit and failed twice in the first 5 requests, a $50,000 credit reduction would occur ($100,000 curtailment credit x 25% x 2). The curtailment credit achieved to that date would be $50,000 ($100,000 curtailment credit less the $50,000 credit reduction). Half of this amount, or $25,000, would be considered vested after the 5th curtailment request. Beginning with the 6th request, the customer would remain subject to the penalty clause. If another curtailment failure occurs, it will result in a further $12,500 credit reduction ($100,000 curtailment credit x 12.5%). The customer's credit for the winter period would then be $37,500 ($50,000 curtailment credit achieved after the 5th request less the $12,500 credit reduction). If the customer then fails to curtail a 4th time, then (i) the customer's credit would be limited to the amount vested after the 5th Curtailment request, or $25,000 and (ii) the customer would no longer be able to participate in the Option.

[21] In 2013-2014, there were 7 Option requests as a result of a supply shortage event. In 2014-2015, there were 2 such Option requests.

[22] The Board's consultant in its investigation into the January 2014 supply shortage and power outage event, The Liberty Consulting Group, in their Interim Report of April 24, 2014 found the outages "…..stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands, and (b) issues with the operation of key transmission system equipment" and further that "…..a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons." These findings were essentially confirmed in The Liberty Consulting Group's Final Report addressing Newfoundland and Labrador Hydro of December 17, 2014.

[23] This is practical in terms of (i) quantifying the amount of curtailment achieved and (ii) the cost of providing metering to a group. For quantification of results, larger load curtailments tend to be easier to observe and quantify whereas smaller load curtailments may not be as easily observed due to the load characteristics of the customer. For metering costs, it costs approximately $2,500 to install a load recorder meter. There is also an annual cost of $250 per meter for telephone service to able to access the recordings. The current maximum cost to connect a customer that can curtail 300 kW is approximately $9/kW [($2,500 + $250) / 300 kW]. With the proposed grouped curtailment, that maximum cost would be $27/kW, triple the current amount and approximately the amount of the annual curtailment credit.

and a single point of customer contact would be required.[24] The credit would be distributed to the group participants based upon a pre-determined allocation.[25]

5.3 Value of the Credit

In customer consultations on the Option, it was suggested that the value of the curtailable credit be increased.

Interruptible or curtailable credits are typically valued at the estimated marginal cost of capacity.[26]

Current interruptible rates negotiated by Hydro and 2 of its industrial customers indicate a rate of \$28/kW.[27] Newfoundland Power's current Option credit at \$29/kVA is comparable to this amount.

The amount of Newfoundland Power's current curtailment credit appears reasonably consistent with other Canadian jurisdictions.[28]

The marginal cost of capacity for the Island Interconnected system is currently unclear.[29] Up to the time of interconnection to the Northern American grid, the Option provides value to the Island Interconnected system.[30] But the value of the Option after interconnection is uncertain. In light of this uncertainly, it does not appear appropriate to change the value of the Option at this time.[31]

Given these circumstances, Newfoundland Power is not proposing any change to the current \$/kVA curtailment credit.

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24 For example, if, as a group, one failure occurs because one participant does not curtail, the failure will result in a 25% penalty for the entire group.

25 The pre-determined allocation would be required to be agreed on by the group participants and the Company before the start of the winter peak season.

26 For example, Manitoba Hydro's curtailable service option referenced discount is related to the marginal value of capacity.

27 See the responses to Requests for Information PUB-NLH-461 and NP-IC-022 filed as part of Hydro's Amended 2013 General Rate Application.

28 See Table 1, page 3.

29 See *Section 6.3.2: Marginal Cost Outlook*, page 6-8, footnote 14.

30 See footnote 1.

31 This is consistent with sound public utility practice. For example, the Manitoba Public Utilities Board has recently found that any expansion to Manitoba Hydro's Curtailable Rate Program ("CRP") would be premature given the construction of the 695 MW Keeyask Generating Station in Northern Manitoba. Page 88 of Order No. 73/15 (July 24, 2015), issued by the Manitoba Public Utilities Board, states: "The Board accepts Manitoba Hydro's explanation that, at the present time, the value of the CRP is diminished and notes that new long term capacity resources in Manitoba, once Keeyask is constructed, will not be required until 2033/34. As such, while the Board believes that there may be merit in MIPUG's suggestion that an expanded CRP with long term contracts could provide capacity benefits, it is premature at this time to expand the program. The Board therefore approves the finalization of Manitoba Hydro's proposed changes to the CRP, including the proposed cap."

5.4 Proposed Curtailable Service Option

Appendix B shows the Company's proposed Curtailable Service Option. Additions necessary to give effect to Newfoundland Power's proposals are indicated by shading.

NEWFOUNDLAND POWER INC.
CURRENT CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:

1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURRENT CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4, that can reduce their demand ("Curtail"), whether individually or in aggregate, by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Customers that reduce their demand in aggregate will be treated as a single Customer under this rate option. The aggregated Customer must provide a single point of contact for a request to Curtail.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced for failure to Curtail in a winter period as follows:

1. For the first 5 curtailment requests the Curtailment Credit will be reduced 25% for each failure to Curtail.

2. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested ("Vested Curtailment Credit").

3. For all remaining curtailment requests the Curtailment Credit will be reduced by 12.5% for each additional failure to Curtail.

If a Customer fails to Curtail four times during a winter period, then:

1. The Customer shall only be entitled to the Vested Curtailable Credit, if any.

2. The Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraphs, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

Supply Cost Mechanisms

October 2015

Table of Contents

1.0 BACKGROUND

1.1 Introduction

This is a report on the results of a review of the regulatory mechanisms that affect the power supply costs of Newfoundland Power.

Amongst other things, this review specifically included (i) a survey of supply cost recovery practices of other investor-owned distribution utilities in Canada; (ii) the performance of Newfoundland Power's regulatory mechanisms that impact purchased power costs; and (iii) a review of the incentive effects of the regulatory mechanisms including an assessment of whether alternative regulatory mechanisms would improve the incentive for the Company to reduce purchased power costs.

The principal supply cost mechanism for Newfoundland Power is its Rate Stabilization Account ("RSA"). The RSA was created primarily as a means of ensuring that variations in Newfoundland and Labrador Hydro ("Hydro") production costs which were captured in Hydro's Rate Stabilization Plan ("RSP") were recovered in, or credited to, Newfoundland Power's customer rates in a timely fashion. The RSA still serves this purpose. The RSA also serves as a means of crediting to, or recovering from, customer rates variations in Newfoundland Power's purchased power expense. This report will consider the RSA principally in the context of Newfoundland Power's purchased power expense and related regulatory mechanisms, not in the context of Hydro's RSP.

1.2 Newfoundland Power's Supply Costs

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[1] Purchased power expense is Newfoundland Power's largest cost, accounting for almost two-thirds of revenue from rates in 2014.

Newfoundland Power's single supply dependence is relatively rare for investor-owned electric utilities in Canada.[2] Currently, the Company effectively recovers its power supply costs through a combination of customer rates and regulatory mechanisms.

1 Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet increasing customer load.

2 In Ontario and Alberta, energy supply for distribution to consumers is coordinated at a wholesale level by independent market operators which effectively ensure least cost supply on a real-time basis through competitive bidding. In Nova Scotia, Prince Edward Island and British Columbia, electric utilities are practically able to seek competitive sources of energy supply in regional wholesale markets. Saskatchewan, Manitoba, New Brunswick, and Quebec do not have investor-owned electric utilities.

Table 1 shows revenue and purchased power expense for Newfoundland Power on a kWh basis for 1994, 2004 and 2014.

Table 1
Revenue and Purchased Power Expense
1994, 2004 and 2014
¢ per kWh

	1994	2004	2014
Revenue	7.75	8.12	10.68
Purchased Power Expense	4.31	4.90	6.83
Purchased Power Expense as % of Revenue	56%	60%	64%

Over the last 20 years, Newfoundland Power's electricity rates and revenues have increased primarily as a result of increased purchased power expense. Over the last 10 years, purchased power expense has increased as a proportion of Newfoundland Power's revenue. On a kWh basis, almost 90% of the change in Newfoundland Power's revenues over this period is attributable to increased purchased power expense.[3] Purchased power expense is substantially beyond management control in any year.

2.0 REGULATORY MECHANISMS

2.1 National Overview

Mechanisms that permit full recovery of energy supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.[4] The widespread use of such regulatory mechanisms simply reflects that, in both the electricity and the gas distribution business, the cost of supply is typically the largest single cost.

Appendix A is a summary of current supply cost recovery practices for regulated investor-owned distribution utilities in Canada.

2.2 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved a definition of a Demand Management Incentive ("DMI") Account to be included in the Company's system of accounts.

The DMI Account is charged or credited with the amount by which the demand supply cost variance exceeds the demand management incentive which is ±1 percent of test year wholesale demand charges.

[3] Change in unit supply costs of 2.5¢ divided by change in unit revenues of 2.9¢ equals 86%.
[4] Such regulatory mechanisms also appear to be commonplace in the U.S. See *Expert Evidence of Concentric Energy Advisors, Appendix A, Comparison to U.S. Electric Utility Proxy Group*, page 28, lines 17 to 24.

Table 2 shows a summary of the demand cost variations for the years 2010 through 2014, with a breakdown of the savings allocation between the Company and its customers.

Table 2
DMI Account
Demand Cost Variations
($000s)

	2010	**2011**	**2012**	**2013**	**2014**
Demand Cost Variance[5]	(1,539.4)	(2,345.8)	(1,330.7)	965.3	(1,221.5)
Company (Savings) Cost	(545.2)	(545.2)	(545.2)	582.2	(594.0)
Customer (Savings) Cost	(994.2)	(1,800.6)	(785.4)	383.1	(627.5)

Since 2010, the operation of the DMI Account has resulted in net demand cost savings to the benefit of both customers and the Company. Since 2010, approximately $3.8 million of the $5.5 million in cumulative net savings has been credited to the benefit of Newfoundland Power's customers.

Newfoundland Power files an annual application with the Board by March 1st to address the disposition of any balance in the DMI Account. Any required recovery from, or credit to, customers arising from a DMI balance is typically included in the Company's annual RSA adjustment.[6]

2.3 Energy Supply Cost Variance Clause

Changes in the Company's purchased power expense related to variances in customers' load requirements are captured by the energy supply cost variance clause. Newfoundland Power's load requirements increase annually, principally as a result of the connection of new customers. The Company is obligated to provide service to new customers.

[5] The demand cost variance is derived from test year unit demand cost. Transfers to reserves are on an after-tax basis. Benefits credited to customers through amortizations or through the RSA are effectively on a before-tax basis.

[6] By Order Nos. P.U. 7 (2011), P.U. 9 (2012), P.U. 8 (2013), P.U. 7 (2014), and P.U. 8 (2015), the Board approved the disposition to customers of the balance resulting from the operation of the DMI Account in 2010, 2011, 2012, 2013 and 2014, respectively, through the annual RSA adjustment. Section II(6) of the Rate Stabilization Clause provides for adjustments to the RSA upon order of the Board.

Table 3 shows Newfoundland Power's marginal supply costs from Hydro and the average supply costs recovered in customer rates for 2010 through 2016F.

Table 3
Energy Supply Cost[7]
2010 to 2016F
(¢/kWh purchased)

	2010	**2011**	**2012**	**2013**	**2014**	**2015F**	**2016F**
Average	5.6	5.6	5.6	5.6	5.9	5.9	6.4
Marginal	8.8	8.8	8.8	8.8	8.8	8.8	9.5
Difference	**(3.2)**	**(3.2)**	**(3.2)**	**(3.1)**	**(2.9)**	**(2.9)**	**(3.1)**

Table 3 shows that wholesale energy cost dynamics on the island of Newfoundland have been such that the cost to Newfoundland Power of the additional energy supply required to serve new customers is greater than the average energy supply cost reflected in customer rates.[8] This annual shortfall of approximately 3.0 ¢/kWh is expected to continue, at a minimum, until interconnection to the North American grid.

This shortfall impairs Newfoundland Power's ability to recover not only its purchased power costs from Hydro but also its own costs of providing service. To ensure reasonable recovery by Newfoundland Power of this increased supply cost without the requirement for a general rate application, the Board approved the annual recovery of energy cost variances through the RSA.[9]

Table 4 shows energy supply cost variances captured by the energy supply cost variance clause from 2010 through 2016F.

Table 4
Energy Supply Cost Variances
($000s)

2010	**2011**	**2012**	**2013**	**2014**	**2015F**	**2016F**
2,213	6,896	9,727	7,836	1,838	3,795	4,526

Any required credit to, or recovery from, customer rates arising from energy supply cost variances are included in the Company's annual RSA adjustment.

[7] Based on January prices.
[8] This wholesale energy cost dynamic has existed since the Energy Supply Cost Variance mechanism was initially approved in 2007.
[9] This was first approved in Order No. P.U. 32 (2007) and continued by Order No. P.U. 43 (2009).

2.4 Weather Normalization Reserve

Newfoundland Power's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and purchased power expense.[10]

Table 5 shows annual Weather Normalization Reserve transfers from 2010 through 2014.

Table 5
Weather Normalization Reserve
Transfers (To) From
($000s)

	2010	2011	2012	2013	2014
Annual transfers to the Weather Normalization Reserve[11]	(5,873)	(3,065)	216	(1,712)	33
Annual transfers to the RSA	-	-	-	(216)	1,712
Amortization of 2011 balance	-	-	-	1,673	1,673

Beginning in 2013, the Board approved, in Order No. 13 (2013), the transfer of the annual balance in the Weather Normalization Reserve to the RSA.[12] In this order, the Board also approved the 3-year amortization of the 2011 year-end reserve balance due to customers.[13] This amortization is reflected in current customer rates.

3.0 ASSESSMENT

3.1 General

Newfoundland Power's purchased power expense accounted for approximately 64% of the Company's revenue in 2014. The Company's current supply cost recovery mechanisms essentially provide the Company with the reasonable opportunity to recover this expense.

[10] The Weather Normalization Reserve has two components: the Hydro Production Equalization Reserve (the "Hydro Component") and the Degree Day Normalization Reserve (the "Degree Day Component"). The Hydro Component effectively adjusts for the effects on purchased power expense that result from abnormal stream-flows to the Company's hydro-electric plants. The Degree Day Component effectively adjusts for the effects of abnormal weather (i.e., temperature and wind speed) on contribution from sales (i.e. change in revenue from rates less change in purchased power expense). The Hydro Component of the Weather Normalization Reserve was approved in Order No. P.U. 32 (1968) and the Degree Day Component was approved in Order No. P.U. 1 (1974).

[11] Annual transfers to the Weather Normalization Reserve for 2010 to 2012 include an annual amortization of ($1.4) million as a result of Order No. P.U. 32 (2007), where the Board approved recovery of approximately $6.8 million through customer rates over a five year period.

[12] By Order Nos. P.U. 11 (2013), P.U. 11 (2014), and P.U. 11 (2015), the Board approved the disposition to customers of the balance resulting from the operation of the Weather Normalization Reserve in 2012, 2013 and 2014, respectively, through the annual RSA adjustment.

[13] The 2011 year-end balance of approximately $5.0 is being amortized over a three year period ending in 2015.

Regulatory mechanisms which provide a utility with a reasonable opportunity to recover its prudently incurred supply costs are consistent with both sound public utility regulation and current Canadian practice. Such mechanisms are routinely commented upon favorably by credit rating agencies.[14]

3.2 Incentive Effects

3.2.1 Incentives to Demand and Energy Conservation

Newfoundland Power has both financial and customer service incentives to foster conservation of demand and energy by its customers.

From a financial perspective, the DMI Account provides Newfoundland Power an incentive to reduce demand which is equal to the cost of ±1% of its annual peak each year, or approximately $1.2 million.[15] This translates into approximately 25% of the 36 basis point range of return on rate base typically approved by the Board for Newfoundland Power. The Company's response to this incentive has reduced purchased power expense from what it otherwise would have been and operation of the DMI Account has provided tangible benefits to customers.

From a customer service perspective, Newfoundland Power's customers have indicated that they wish to lower their energy bills. Newfoundland Power's satisfaction of its customers' service expectations in this regard provides a customer service incentive for the Company to take reasonable steps to foster energy conservation by its customers. Newfoundland Power has responded reasonably to this incentive.[16] This response has reduced Newfoundland Power's purchased power expense from what it otherwise would have been and provided tangible benefits to its customers.

3.2.2 Regulatory Policy Analysis

The justification of Newfoundland Power's current supply cost mechanisms reflects a combination of current dynamics related to production, wholesale and retail pricing, and customer end use on the island interconnected grid.

Hydro's Holyrood generating station is both a significant contributor to annual energy production and is the marginal source of supply on the island interconnected grid. Holyrood fuel costs are highly variable and justify the current mechanisms which provide for fuel recovery through Hydro's RSP and Newfoundland Power's RSA.

Wholesale and retail pricing on the island interconnected grid affects supply cost mechanisms in at least 2 significant ways. Firstly, Hydro's current wholesale utility rate design was explicitly

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14 See for example the credit opinions of Moody's Investors Services and Dominion Bond Rating Service which are *Exhibit 4*, in *Volume 2, Exhibits & Supporting Materials*.

15 Based upon the 2014 test year.

16 Newfoundland Power's response has been to jointly promote with Hydro a customer energy conservation portfolio which is aimed at reducing customer energy usage and, in turn, reducing the production costs of Hydro. For more detail on this program portfolio; its costs and impacts; and plans for its expansion; see Section 2.2.2.

created to encourage demand conservation by Newfoundland Power.[17] The DMI Account achieves this. Secondly, current wholesale utility rate design and retail rate design combine to ensure that, following a test year, Newfoundland Power effectively serves new customers at a loss.[18] The energy supply cost variance clause avoids the alternative of more frequent general rate applications.

Newfoundland Power continues to serve a substantial heating load. Variations in weather, therefore, can have a substantial affect on the Company's purchased power expense. The Weather Normalization Reserve effectively addresses the relatively high impact of weather for Newfoundland Power.[19]

The Company's current supply cost mechanisms specifically meet local regulatory policy objectives and are consistent with current Canadian regulatory practice. No superior mechanisms in terms of incentive effects or otherwise were identified by Newfoundland Power in the review.

4.0 CONCLUSION

This review indicated that current mechanisms which provide for the Company's recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice. The review also indicated existing mechanisms provide reasonable incentives for the Company to foster customer conservation of demand and energy. These incentives have yielded tangible results that benefit customers.

As a result, the Company is not proposing any changes to these regulatory mechanisms.

[17] For example, in Order No. P.U. 44 (2004), the Board indicated at page 10 that a key question for it was whether there was "….sufficient incentive for [Newfoundland Power] to implement load management and conservation programs aimed at reducing demand growth on the system, and hence reduce its purchased power costs through a lower billing demand."

[18] This dynamic was recognized by the Board in Order No. P.U. 32 (2007) when, in approving the energy supply cost variance clause, it observed at page 27 that "The recovery of variances in energy supply costs through the Rate Stabilization Account will allow [Newfoundland Power] to recover its prudently incurred energy supply costs without the necessity of filing a general rate application, which is consistent with the Board's goal of enhanced regulatory efficiency."

[19] All Canadian investor-owned gas or electric distribution utilities surveyed by Newfoundland Power that serve substantial heating loads have regulatory mechanisms which effectively provide for full recovery of supply costs after consideration of the effects of weather (See Appendix A).

Supply Cost Recovery Practices for Regulated Investor-owned Distribution Utilities in Canada

	Province	Supply Cost in Customer Rates	Flow-through Mechanism	Mechanism Description
Electric Utilities				
Maritime Electric	PEI	Yes	Yes	Energy Cost Adjustment Mechanism that provides for recovery or refund to customers of the variation from test year energy supply costs. (See Note 1)
FortisOntario	Ontario	Yes	Yes	Variance account to capture price differentials between the actual supply cost and supply cost reflected in customer rates. (See Note 2)
FortisAlberta	Alberta	No	Not Required	(See Note 3)
ATCO Electric	Alberta	No	Not Required	(See Note 3)
FortisBC	BC	Yes	Yes	Rate Stabilization Deferral Mechanism Account (RSDM) used to mitigate rate variability over the PBR Period.
Gas Utilities				
GazMetro	Quebec	Yes	Yes	Rate stabilization regulatory mechanisms to account for the impacts of weather and the cost of energy. Balance disposition in subsequent year(s).
Union Gas	Ontario	Yes	Yes	Rates are adjusted on a quarterly basis and the difference between the cost of gas reflected in rates and the actual cost of gas is deferred. Disposition of the forecast balances in the deferral account occurs over the subsequent 12 months.
Enbridge Gas Distribution	Ontario	Yes	Yes	The difference between the cost of gas in rates and the actual cost of gas is deferred to be recovered from, or refunded to, customers through a quarterly adjustment mechanism. There is also a true-up account to recover the financial impact of variances from forecast average use for residential and commercial sectors.
ATCO Gas	Alberta	No	Not Required	(See Note 3)
AltaGas Utilities	Alberta	Yes	Yes	A Gas Cost Recovery Rate (GCRR) is updated monthly to ensure the actual cost of gas is recovered from customers. (See Note 4)
FortisBC Energy	BC	Yes	Yes	Rate stabilization mechanisms to mitigate the effect on earnings of volume volatility due to the effects of weather and natural gas cost volatility. (See Note 5)
Pacific Northern Gas	BC	Yes	Yes	Regulatory mechanisms to mitigate the effect on earnings of volume volatility and natural gas cost volatility. (See Note 6)

Notes:

(1) The Energy Cost Adjustment Mechanism ("ECAM") adjusts for monthly variances from the 8.760 ¢ per kWh test year energy supply cost, and the balance is recovered or refunded, as appropriate, over a rolling 12-month period. The PEI Energy Accord currently stipulates the term of the disposition of the balance related to the ECAM.

(2) The Electricity Distribution Rate Handbook approved by the Ontario Energy Board provides for a purchased power variance/deferral account for distribution utilities to capture price differentials between the actual electricity supply costs and the supply cost reflected in customer rates.

(3) FortisAlberta, ATCO Electric, and ATCO Gas own and operate assets that provide distribution service under Alberta Utilities Commission approved distribution tariffs. Distribution tariffs provide for a recovery of the cost of distribution service including a fair return. Electricity and gas supply costs are not considered a cost of these utilities' provision of distribution service. Supply costs are a separate component on customers' bills.

(4) The GCRR is updated monthly to reflect an estimate of the cost of gas and gas supply-related management and administration costs for the upcoming month and to adjust for any deficit or surplus from the previous month.

(5) Two rate stabilization mechanisms are used at FortisBC Energy.

The first relates to recovery of gas costs through two deferral accounts which capture all variances (overages and shortfalls) from forecasts gas costs. The deferral accounts are called the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA).

The second mechanism stabilizes delivery revenues from the residential and commercial classes through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (RSAM). If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, Terasen records the delivery charge differences in the RSAM deferral account.

The BCUC has issued guidelines for quarterly calculations to be prepared to determine whether customer rate adjustments are needed to reflect the market price of natural gas and to ensure that rate stabilization account balances are recovered on a timely basis.

(6) Two rate stabilization mechanisms are used at Pacific Northern Gas.

The first in the Gas Cost Variance Account which is utilized to record variances in the actual cost of gas and the cost reflected in customer rates.

The Revenue Stabilization Adjustment Mechanism adjusts revenue from residential and small commercial customers by a deferral account that records differences between forecast and actual deliveries.

When deliveries to customers vary from forecast, balances accumulate in the accounts which are recovered, or refunded, as appropriate in future rates to customers.